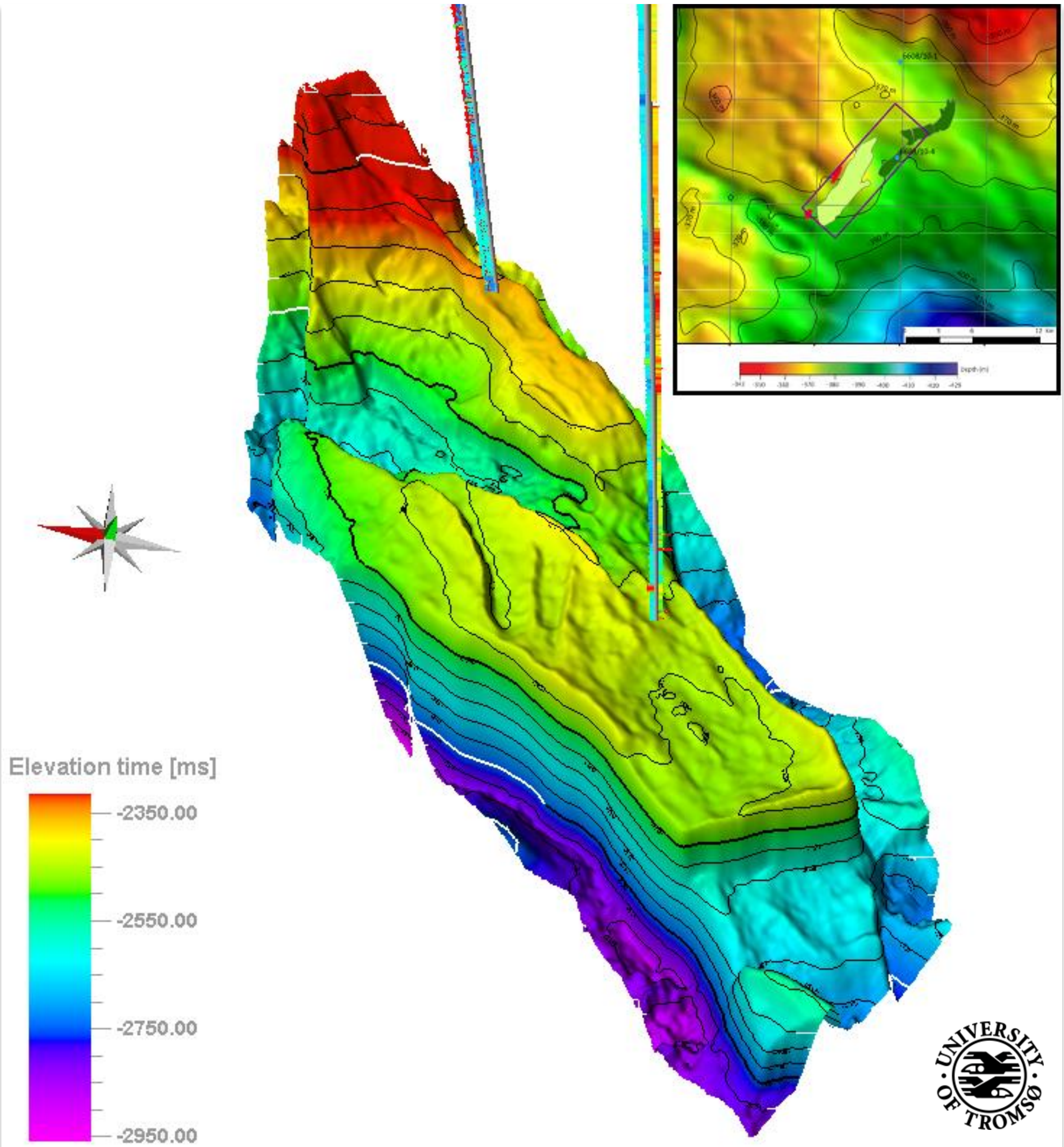
FACULTY OF SCIENCE AND TECHNOLOGY
DEPARTMENT OF GEOLOGY

Integrated Petrophysical and Seismic interpretation of Norne Field, Norway.

Reservoir Study of Norne Field, Norway

Adnan Khan

GEO-3900 Master's Thesis in Geology
September 2014



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Abstract

The aim of this thesis is to evaluate petrophysical properties and seismic interpretation of main reservoirs of Norne field in Mid Norwegian sea. Petrophysical evaluation helps in getting familiar with reservoir characterization using wireline logs data. The main concentration has been given to evaluate different reservoir properties i.e. porosity, shale volume, water saturation, hydrocarbon saturation, permeability and lithology indications. This petrophysical analysis indicates the quality of reservoirs and hydrocarbon presence. These studies show that reservoir in Norne field is of good to very good properties with average porosities ranges between 19% to 26%, water saturation from 20% to 36% in the hydrocarbon zone and 187 to 1087 mD.

Seismic studies are carried to interpret the different horizons, faults and bounded structures. A total of six horizons were interpreted in 3D seismic dataset ST9203R03. Top Spek, Top Garn, Top Ile, Top Tofte, Top Tilje and Top Åre. The surface of Top Garn (Top reservoir) was of main interest of the interpretation. Through the interpretation , different geological features such as blocks, faults, floors and a trench were recognized.

اقْرَأْ بِاسْمِ رَبِّكَ الَّذِي خَلَقَ ﴿١﴾ خَلَقَ الْإِنسَانَ مِنْ عَلَقٍ ﴿٢﴾
اقْرَأْ وَرَبُّكَ الْأَكْرَمُ ﴿٣﴾ الَّذِي عَلَّمَ بِالْقَلَمِ ﴿٤﴾ عَلَّمَ الْإِنسَانَ
مَا لَمْ يَعْلَمْ ﴿٥﴾

1. Read in the name of thy Lord who creates
2. Creates man from a clot,
3. Read and thy Lord is most Generous,
4. Who taught by the pen,
5. Taught man what he knew not.

Sūrat al-ʿAlaq, 96th chapter of the Qur'an

ACKNOWLEDGEMENTS

First of all I would like to thank mighty Allah for guiding me on to right path and helping me in achieving my goals.

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At the end, I would like to say special thanks to my parents, grandmother, uncle and brothers. Without their prayers and guidance, I wouldn’t have made this far.

Adnan Khan

September, 2014

Contents

1 Introduction

This thesis is about Integrated Petrophysical and Seismic studies of Norne field,Norway. The main primary objectives of the thesis are, getting familiar with reservoir characterization using wireline logs, identification and interpretation of multiple reservoirs. While secondary objective is Structural and stratigraphic studies using seismic data. Thesis is divided in to two parts, Seismic interpretation and Petrophysical evaluation of reservoirs.

For this purpose, softwarer used are Petrel(Schlumberger) for seismic interpretation & Geolog (Paradigm) for Petrophysical evaluations.

Norne field was discovered in December 1991. Its is a Horst block and is approximately 9*3 km. It is located 80 km north from Heidrun field in Norwegian sea. The field is situated in block 6608/10 and 6508/1 in the southern part of Nordland II area (figure 1).

The Norne field has been on flow since 1997 and only the future can tell for how long it will produce. My thesis main objectives are both seismic and petrophysical evaluation at reservoir depth. Seismic interpretation in this thesis help in studying the area in detail and help me to know more about different structure, I'm going to encounter. I'll mark 6 horizons. Spek formation, Garn Formation, Ile Formation, Tofte formation, Tilje formation and Åre formation. Then I'll interpret different horizons and fault related. At the end I'll generate different surfaces and compile 3D surfaces with fault interpreted.

The petrophysical evaluation of the Norne main field is based on data from the two exploration wells 6608/10-2 and 6608/10-4 with the help of wireline log data.

2 Introduction to the Norne Field

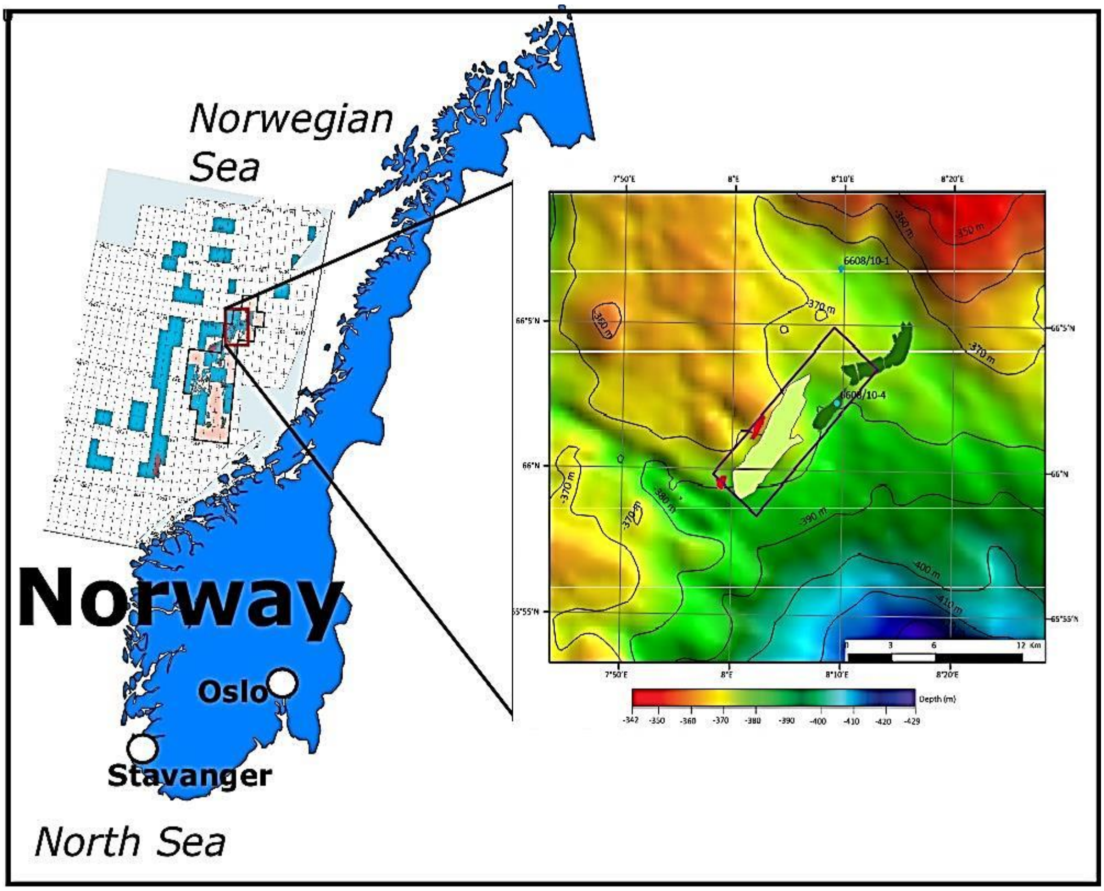


Figure 1: Location of Norne Field within the Norwegian Sea (modified from Statoil, 2006)

2.1 Location and Production

The Norne field is in the southern parts of the Nordland II area in the Norwegian Sea (Statoil,2004). It is located in the blocks 6608/10 and 6508/01; the field was discovered in 1992 and is operated by Statoil Petroleum AS (Norwegian Petroleum Directorate).

Its original reserves were estimated to be (numbers in parenthesis indicating remaining estimates as of 2013):

- 90.8 (3.8) million Sm3oil
- 12.0 (5.4) billion Sm3gas
- 1.6 (0.8) million tons NGL

As these numbers show a large fraction of the originally estimated volumes have already been produced (in particular oil) but with increasing focus on new technology such as increased oil recovery (lOR), the field in 2013 still was expected to produce:

- 11000 barrels of oil/day
- 0.17 billion Sm3 gas
- 0.03 million tonnes NGL

The usual water depth in the area is roughly 380 meters; seven subsea templates are joined with risers to the hovering production and storage vessel Norne FPSO . Several satellites also are connected to Norne FPSO (figure 2).

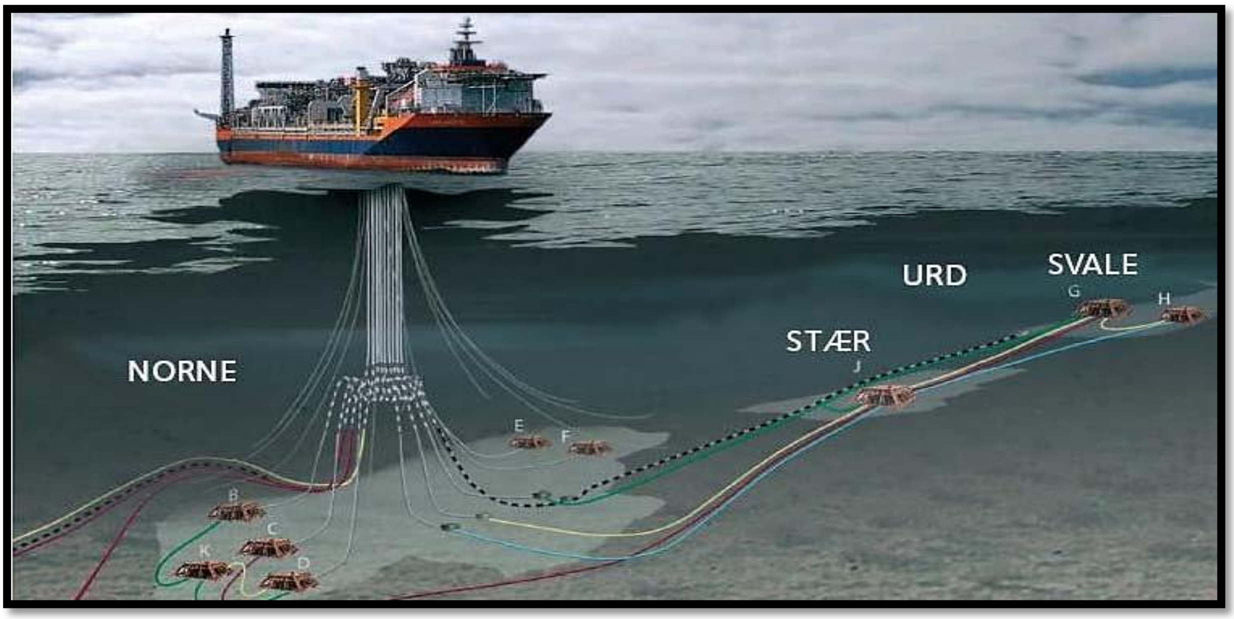


Figure: 2 Several satellites are connected to the Norne FPSO. Below the Norne FPSO the B, C, D, E, F and K.templates can be seen at the sea bed. Template B, D and E are production templates, whereas template C and F are injection templates. Template K is used both for production and injection. Today the drive mechanism is water injection (however gas also has been used until 2005).

2.2 Segments

The Norne Field consists of two divided oil compartments. In turn these are segmented as follows (figure 3):

- The Norne Main Structure (97% of the oil in place)
    - Norne C-Segment
    - Norne D-Segment
    - Norne E-Segment

- The Northeast Segment
  - Norne G-Segment

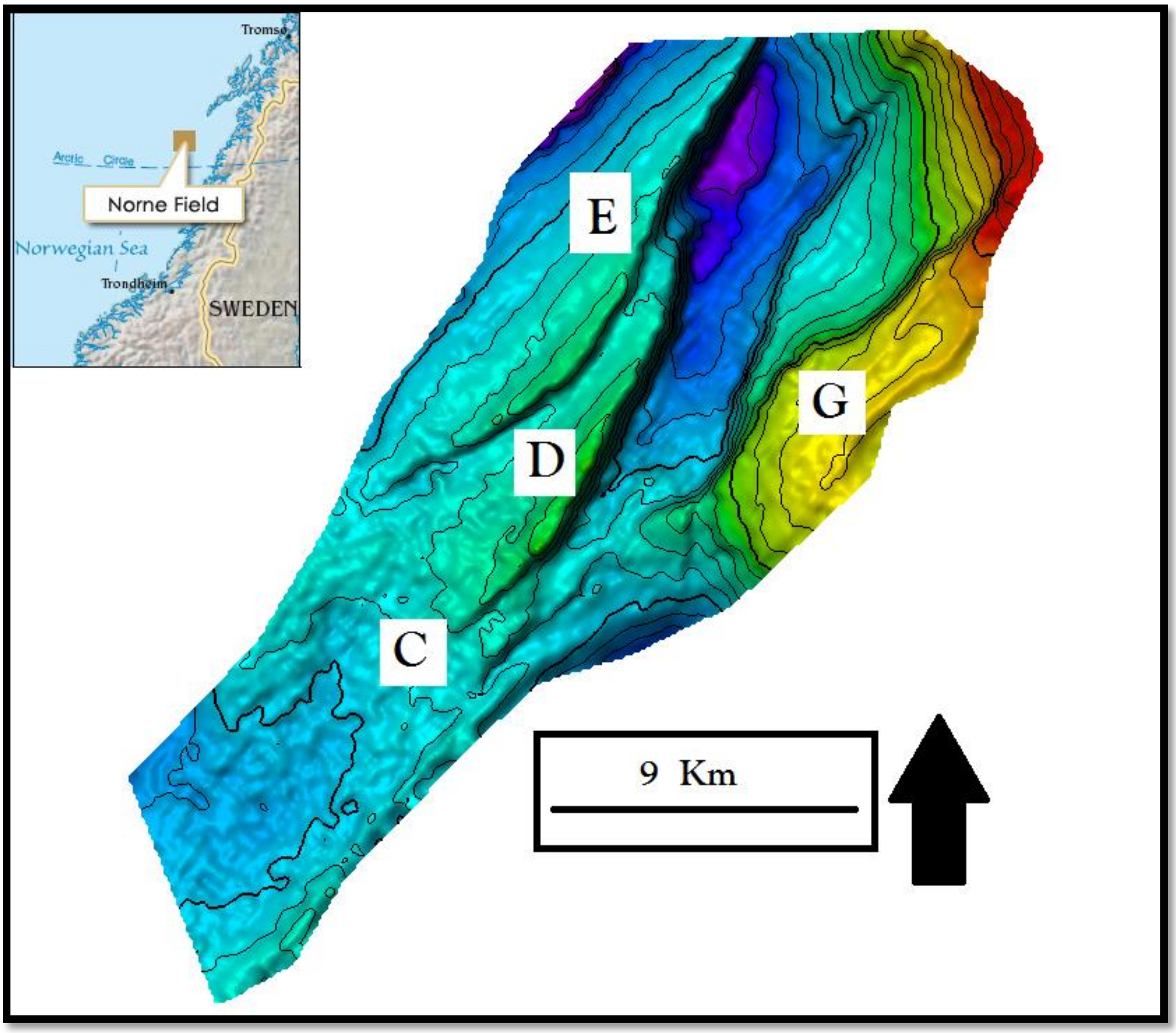


Figure 3: The Norne field with all the segments.

2.3 Definition of Blocks

Instead of referring to the C, D, E and G segments, from an interpreter's point of view in otherwise unknown geology, I quite focus on the main faults and related fault blocks. Using this image as a guideline for the taxonomy throughout the thesis, I hereby define block C, D, E and G. This is pretty understandable from the figure 4 and even though I also interpret small faults and faults blocks that later on stage could make up related segments in a more specific way, I settle for this simplification. (Statoil,2004).

3 Tectonics and Geological information

3.1 The Mid-Norwegian Continental Margin

Even though numerous fault complexes, basin and sub-basins can be found in the Mid-Norwegian Margin, the Møre, Vøring and lofoten-Vesterålen are well thought-out to be the three key segments(Faleide, Bjørlykke, & Gabrielsen, 2010). If we inspect the Mid-Norwegian Margin from SW to NE, we first have the More segment. Then by crossing the East Jan Mayen Fracture Zone, we enter the Vøring segment; this also is where the Norne Field is found. Finally and north of the Bivrost lineament Transfer Zone, we find the lofoten-Vesterålen segment. The More, Voring and lofoten- Vesteriilen margins all range from 400 to 500 km in length towards the Norwegian Sea, where they all dip into their main basins respectively (figure 4). In addition the smaller Halten Terrace and the Nordland Ridge, both found in the Vøring segment, compromise the Norne field.

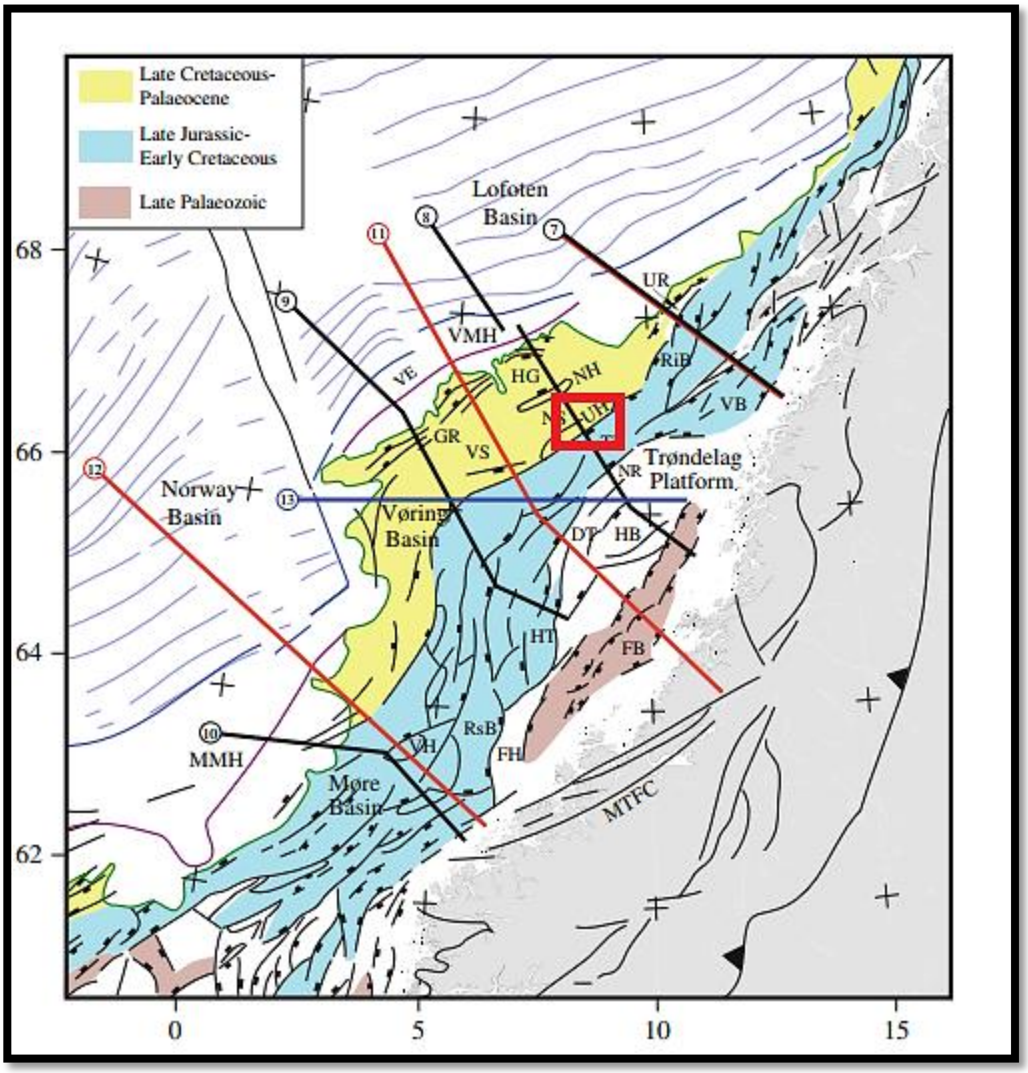


Figure 4: The Møre, vøring, and Lofoten- Vesterålen.segments. The East Jan Mayen Fracture Zone and the Bivrost Lineament Transfer Zone are located around line 12 and 8 respectively. (modified from Blystad et al., 1995). Red box points the location of Norne field location

3.1.1 The Møre Margin

By smoothly sloping into the More Basin, this margin has a somewhat fine shelf (Faleide, Bjørlykke, & Gabrielsen, 2010) . Late Jurassic-Early Cretaceous rifting has shaped both sub-basins and intrabasinal highs, and a thick package of Cretaceous infill runs all the way shelf towards the Møre basin (figure 5). Mid-Cretaceous individual times of grave sedimentation, both sill intrusions and lava flows can also be recognized in the Upper Cretaceous.

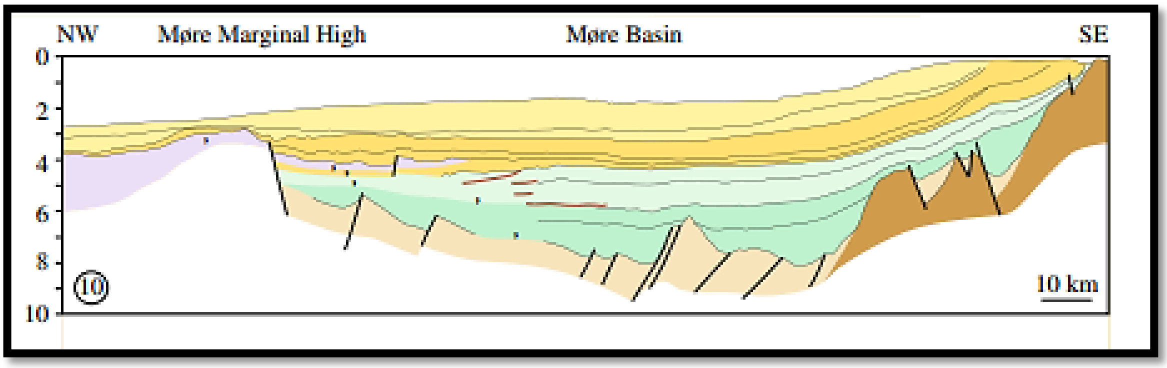
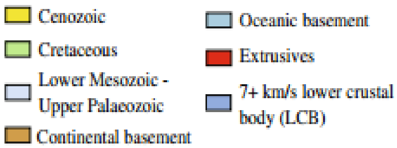


Figure 5: Regional profile displaying the relatively narrow shelf, numerous faults in the Jurassic-Triassic basement, as well as the thick Cretaceous infill. The well-known Møre Marginal High can be seen to the NW of the Møre Basin (Blystad et al., 1995)



3.1.2 The Vøring Margin

Extending all the way from the East Jan Mayen Fracture Zone in the SW to the Bivrost Lineament Transfer Zone in the NE, the Vøring Margin is about 500 km wide (Faleide, Bjørlykke, & Gabrielsen, 2010). This being our margin of curiosity; by follow an outward NW trend from onshore Norway to t he Norwegian Sea, intersecting the Norne Field on the way, we go across the Trøndelag Platform, the Helgeland Basin, the Nordland Ridge and the Halten Terrace, before dipping into the Vøring Basin. If we further carry on in the same direction, we finally end up in the Vøring Marginal High (figure 7).

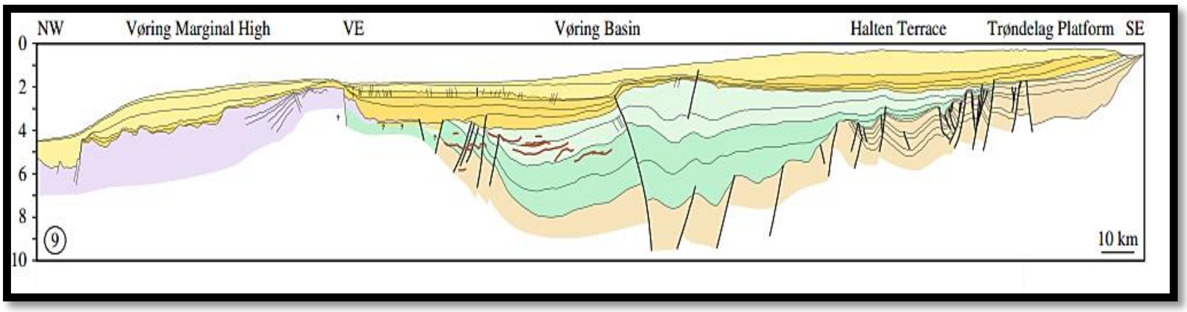


Figure 6: In the Jurassic-Triassic sediments the same Initial rifting regime has created various fault complexes along the margin. The Cretaceous Infill varies in thickness, from thin to thick towards the Vøring Basin. Between the Trøndelag platform and the Vøring Basin, the Halten Terrae can be seen as relatively long and shallow. To the far NE the Vøring Marginal High lies on top of the break up lava (Blystad et al., 1995)

Deep basins differentiate the Trøndelag Platform, the infill mostly being from the Triassic and the Upper Palaeozoic times (figure 6). In addition this platform has been fairly stable from the Jurassic period. As with the Møre Basin, the Vøring Basin also has several sub basins and highs; differential vertical movement from the late Jurassic-Early Cretaceous basin evolution is contemplation to be the key method (Faleide, Bjørlykke, & Gabrielsen,2010). As mentioned the Vøring Marginal High is a well-known bathymetric mark of the Mid-Norwegian Margin. The Vøring Marginal High is a part of the Vøring Plateau and is built up of an oddly thick oceanic crust covered by mafic intrusions and Early Eocene basalts.

3.1.3 The Bivrost Transfer Zone

The Bivrost Transfer Zone both divide the Vøring and Lofoten-Vesteralen segments of the Mid-Norwegian Margin as discussed, and marks the northern extinction of the Vøring Marginal High (figure 7). Between the Vøring Basement and the Vøring Plateau, a small segment called The Vøring Escarpment can be found. Still the Bivrost Transfer Zone cuts through all these segments therefore making it a main fault boundary.

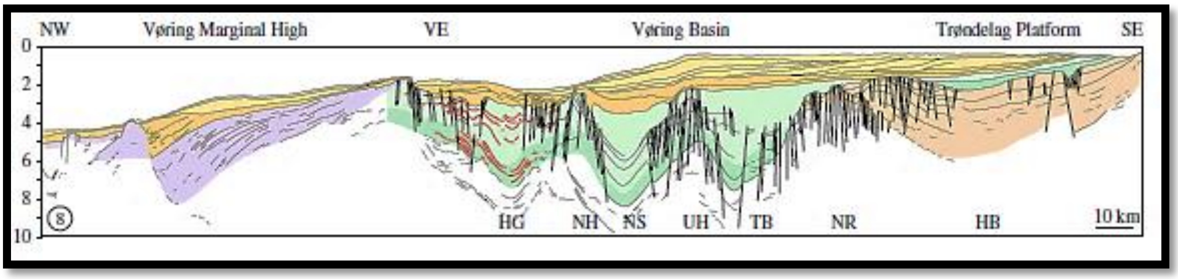


Figure 7: All over the regional profile,extensive.rifting.can be seen in theCretaceous sediments.The margin physiography.of the Bivrost Transfer Zone Is shaped by break·up magnatism and lithosphere stretching (Faleide, Bjølrlykke, & Gabrielsen, 2010). Adjacent areas from SE to NW are the Helgeland Basin, Nordland Ridge, Trøndelag Basin, Utgard High, Nagrind Syndine, Nyk High and Hel Graben (Blystad et al., 1995)

3.1.4 The Lofoten-Vesteralen Margin

While the M0re Margin was smoothly dipping into its basin, the lofoten-Vesteralen Margin has a sharp slope and a parallel narrow shelf (Faleide, Bjørlykke, & Gabrielsen, 2010). The basins beneath the shelf also are shallower than that of the M0re Margin. A variety of asymmetrical half- graben structures can be found in the Lofoten-Vesteralen Basin and underneath the steep slope, break-up lava is covered by Cenozoic and Plio-Pleistocene Glacial Sediments (figure 8).

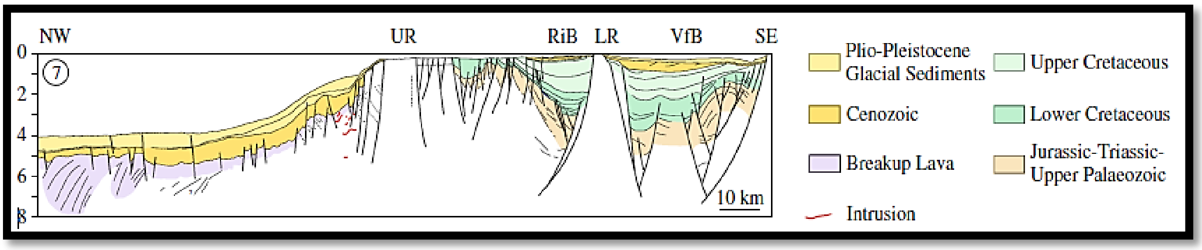


Figure 8: Characteristic half-graben structures followed.by a steep slope towards the NW Compared to the Møre.and Vønngen basins, the Lofoten Basin also consists of several faults. Minor marginal segments in the centre.of this regional profile are the Ribban Basin and the Utrøst Ridge (Blystad et al., 1995)

3.2 Norne stratigraphy and sedimentology

The reservoir is subdivided into four different formations from top to base: Garn, Ile,Tofte and Tilje. In Verlo and Hetland, 2008, Geological informations is well described.

3.2.1 Reservoir-cap Formations

Small formations/segments/parts in between Top Spekk and Top Garn will be Interpreted as Res-Cap I, II and Ill respectively. Where the Spekk and Melke formations co-exist, the Top Melke would usually match to Res-Cap I. These formations are situated above the reservoir and are consequently considered to be of secondary interest (and will not be interpreted in 3D) (Verlo & Hetland, 2008).

3.2.2 The Bat, Fangst and Viking Groups

The Are, Tilje and Tofte formations make up the Bat Group. Further up we find the Fangst Group consisting of the Garn, Not and lie formations. Finally, The Spekk and Melke formations make up the Viking Group. In well 6608/10-2 the Ror Formation can be found at 2659 to 2668 meters (in between the Tofte and lie formations). It fit in to the Bat Group but it will not be deduce in this thesis. On the other hand, it will be mentioned in the early phase of the interpretation (Verlo & Hetland, 2008).

3.2.3 The Åre Formation

Placed in the Early Jurassic, more specifically during Hettangian to Early Pliensbachian times, the Åre formation is the lowest formation and well thought-out a source rock for the reservoir (Verlo & Hetland, 2008). Nevertheless in southern parts of the Halten Terrace it is just 200 meters. Eastward an augmented sand/ration can be seen, assumed to be deposited in an alluvial to delta plain environments facing the conflicting direction; in channel/delta environments the heavier grains first place at high energies. Then the lighter particles will settle as the energy levels drops seaward (Verlo & Hetland, 2008).

3.2.4 The Tilje Formation

The Tilje Formation has conglomerates and sand with some shale (Verlo & Hetland, 2008). Thought to be deposited in tidally affected marginal marine environments, it later on experienced erosion as a tectonic event may have caused uplift. This trend is generally observed to the N-NE at the base of the Tofte Formation; a reduced subsidence rate through the deposition may also have caused the contraction of the Tilje Formation. In contrast to the Are Formation, the key source for sedimentation was situated in the west. The space created from erosion marks the transition zone from the heterolitic composition of the Åre and Tilje Formations into the thicker marine sandstones above (Verlo & Hetland, 2008).

3.2.5 The Tofte Formation

As stated the unconformity marks an central hiatus in the reservoir; the Tofte Formation was dropped on top of this during Late Toarcian time (Verlo & Hetland, 2008). In addition the Tofte Formation is anticipated to be about 50 meters thick in average throughout the field. Marine from foreshore to offshore environments seem to portray the formation. Sands were deposited in to the west of the Nordland ridge, while finer shales can experimental to the east. At the top of the ridge marks of erosion also have been found. The subdivisions of the Tofte Formation are the Tofte 1, 2 and 3 reservoir zones.

The lower parts Tofte 1 are bioturbated fine grains. Further up medium to coarser grained sandstones with sheer dipping lamina can be found. By investigating the dip of the layers, it has been recommended that the source of sedimentation was situated rather N-NE of the Norne field. Another discrete observation made in Tofte 1is the lightly sedimented NE-SW and E-W trends.

Making up a muddy and fine grained sandstone unit subjected to heavy bioturbation, Tofte 2 also has suspended clasts in the lower parts. Tofte 3 is so heavily bioturbated that barely any of the geological features has been sealed. The rocks are very fine to fine sandstones, and in the upper parts some low angle dipping can be seen. The Upper Toarcian-Aalenian succession boundary can be found as a coarse grained bed at the top of the unit.

In this thesis the Tofte Formation will be interpreted as Top Tofte. However, we note that both Top Tilje and Top Tofte are not very well connected in any of the wells used. Therefore they frequently correspond to the two strongest reflectors in between Top Ile and Top Are, although some deviations may happen (Verlo & Hetland, 2008).

3.2.6 The Ile Formation

The depositional environment of the ile Formation is supposed to be shore face. In Aalenian times sands were deposited leaving 32 to 40 meters thick sandstones throughout the field (Verlo & Hetland, 2008). The ile Formation is both sub-divided into three zones and has some fascinating boundary interfaces.

Correlations among wells 6608/10-4 and 6608/10-2 propose that this cemented calcareous layer is constant across field. A shift from the regressive style mention above to a transgressive environment then resulted in a sequence boundary that can be found between lie 2 and 3. The Ile formation normally has good reservoir quality with a downward growing trend into the regressive phase. This may be explained by a easy regression- transgression cycle. As the transgression took place the relative water level at a given point improved.

At these points in the formation smaller element were deposited in moderately deeper water, while the larger fractions were deposited further towards land as the energy levels increased accordingly. Furthermore a northward coarsening trend can be pragmatic in the fine to very fine sands of Ile 1 and 2. Nonetheless the depositional transport direction is hard to agree on as the amount of geological features such as ripples and lamination is inadequate. However, these features have endured bioturbation of the formation.

At the top of Ile 1 we get the coarser grained sequence boundary earlier described, and Ile 3 is positioned above this Ile 3 is greatly bioturbated and characterized by its fine to very fine upward fining sandstones. Once again signs of depositional malnourishment such as clay clasts, glauconites and phosphorite nodules can be found in Ile 3 (Verlo & Hetland, 2008).

3.2.7 The Not Formation:

Not formation was also deposited during Aalenian time. It is a 7.5 m thick, dark grey to black claystone with siltstone lamina. The depositional environment was quiet marine, probably below wavebase. However, palynological findings indicate that there was freshwater influencing the environment. This is explainable if one assumes that the water column in the basin was stratified, hence preventing the water from mixing before it reached far into the basin. The Not Formation has a coarsening upward trend which continues into the Garn Formation. Therefore, it can be found a layer of very fine grained, bioturbated sandstone in the upper part of the formation. The upward coarsening indicates deposition during a regression (Verlo & Hetland, 2008).

3.2.8 The Garn Formation

Garn formation was deposited during the Late Aalenian and the Early Bajocian, and is 35 m thick sandstone. The depositional environment was near shore with some tidal influence. Reservoir quality is increasing upward within the formation, from pretty good in the lower parts to very good in the upper parts. This formation is also divided into reservoir zones based on differing properties and deposits. For the Garn Formation the number of reservoir zones is three. Garn 1 is a sandstone unit which is coarsening upward, from very fine to fine grained sand. The lower part is muddy and bioturbated, as it is the continuance of the Not Formation, while the upper part has an increased sand content. This part of the formation has faster beddings, ripple lamination and thin layers of coarser grained sandstone. At the top of Garn 1 a course to very coarse grained, garnet rich bed is found. This bed is interpreted to be a beach deposit from the maximum regression period; it is a sequence boundary that is correlateable in the Norne wells. Garn 2 is a transgressive deposition consisting of fine grained sandstones, where some layers are bioturbated while others are laminated. At the top, a calcareous cemented sandstone unit is discovered. It represents a starvation in the supply also called maximum flooding surface. This layer is expected to be continuous throughout the field and can be a local barrier to vertical fluid flow. The lower part of Garn 3 is not cored in any of the wells. The upper part of this zone is made up of low angled cross bedded and fine grained sandstone. A coarse grained bed is located in the top of Garn 3. This is an erosional surface from maximum regression. The Garn Formation is much thinner in well 6608/10-1 and most of Garn 2 and the entire Garn 3 are missing in this well. This is due to tectonic uplift in the north during the deposition. The Garn Formation south of the Norne field is thicker due to higher subsidence rates, which give more accommodation space. At the top of Garn 3, sandstone and mudstone sediments with floating clasts are found. This is a result of ravinement and reworking during a transgressive period (Verlo & Hetland, 2008).

3.2.9 The Spekk and Melke Formations

Late Bajocian-Early Bathonian is the times of deposition for the Melke Formation. Wells 6608/10-3 and 6608/10-2 have established its thickness from 160 to 212 meters respectively. The Melke Formation primarily consisting of claystone, siltstone lamina can also be found in the formation. Additionally the depositional environment is said to be offshore transitional to lower shoreface. In the north of the field the lower shoreface is the mainly well-known depositional environment, while the field in all-purpose is that of the offshore transitional. These findings recommend that the source of sedimentation was located north of the field. ln the lower parts of the Melke Formation, three upward coursing units have been recognized; all terminating in a very fine grained, muddy sandstone.

Both the Melke and the Spekk formations are clear to be cap rocks of the reservoir and as a result not cored. In addition, well 6608/10-3 and 6608/10-2 only have lithostratigraphic information from the Melke Formation. On the other hand in well 6608/10-4 we find the Spekk Formation from 2328 to 2372 meter . Right below the Spekk Formation, we find the Melke Formation from 2372 to 2567 meters.

Even though only the Melke formation is illustrate in detail here, the two formations both overlap geologically and are consequently also difficult to distinguish in the seismic volume. Given that they both provide the same point for the Norne reservoir, they are interpreted to have one familiar horizon;Top Spekk. ln this thesis Top Spekk also is defined to represent the cap rock of the reservoir (Verlo & Hetland, 2008).

4 The Reservoir

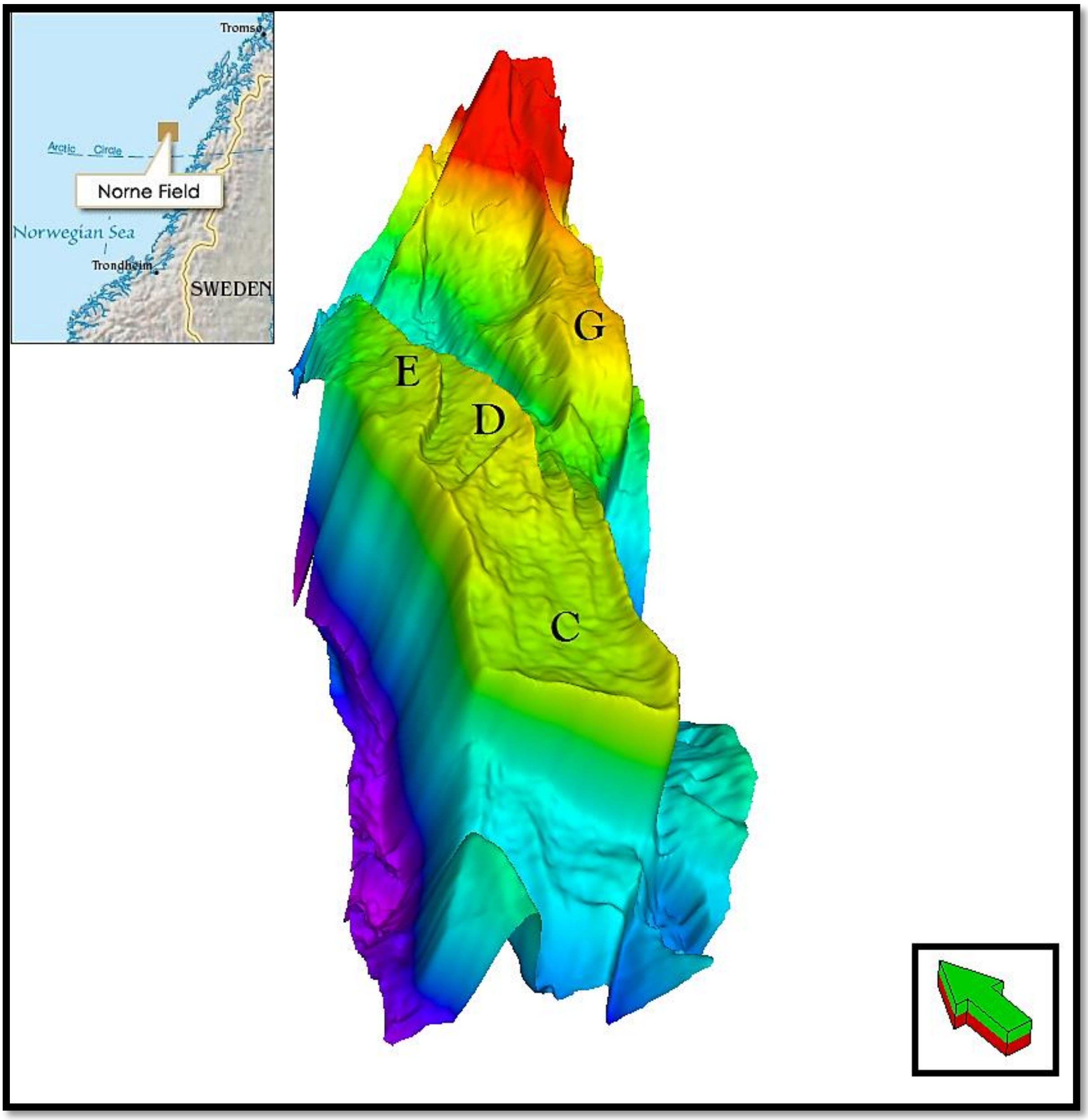


Figure 9: Top reservoir (Garn Formation) showing Norne horst block with four segments., the Garn zonations were later renamed as Not zonations (2006).

The Norne reservoir sandstones are masked at 2500-2700 meter, making digenetic processes such as mechanical compaction noteworthy (Verlo & Hetland, 2008). As both mechanical compaction and cementation diminish permeability and porosity, such situation is considered not good. Still with permeability ranging from 20-2500 mD and porosities as high as 25-30 %, the reservoir has established to be of good quality. In general the reservoir sandstones comprises of well to very well sorted and fine-grained sub-arkosic arenites. As for the mineralogy, with quarts being the main mineral an arkose has at least 25 % feldspar (Folk,1981), and arenites contain less than 15% matrix (Britannica definition of arenites).

The reservoir has two key seals; interlaying the ile from the middle Not formations, we have the lower Not formation. This is a claystone formation avoid communication between the two sandstones. On top of the reservoir itself we find the main cap rock, the Melke formation (upper Not formation, Zonation 2006) .

The depositional environments from base to top consist of bay deposits and mouth bars, tidally influences deposits, shallow marine and shoreface deposits, and channelized sandstones. As the quantity of information over a producing field enhance over time, so may the value of the geological model. A zonation from 2002 and 2006 shows how diverse compartments of the reservoir has been added and removed to best portray the geology (figure 10) (Statoil, 2001).

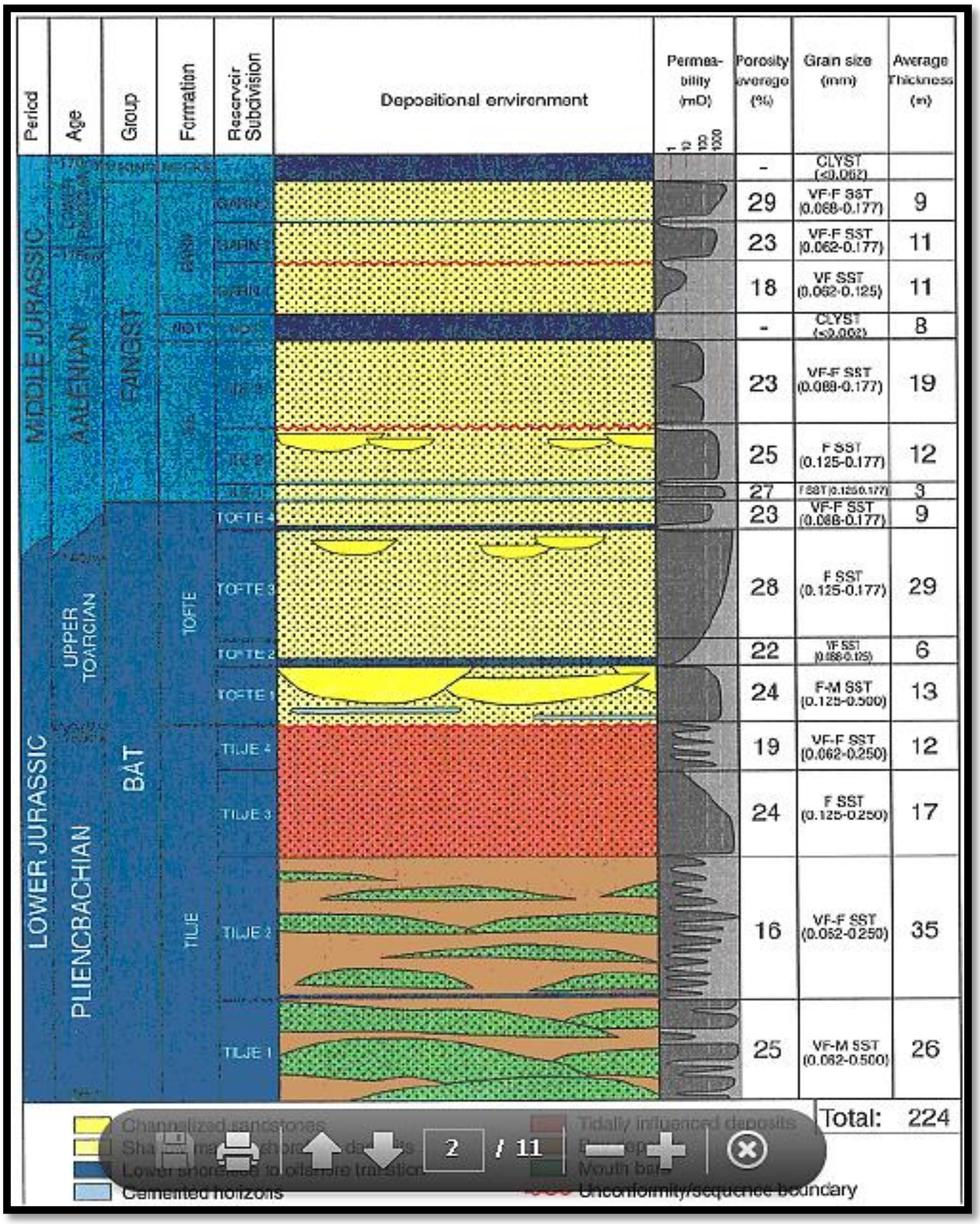


Figure 10: Stratigraphical sub-division of the Norne reservoir (Statoil, 2001).

<table>
<tr><th colspan="2">NORNE 2002</th><th colspan="3">NORNE 2006</th></tr>
<tr><td>Lower Melke</td><td></td><td>Not 3</td><td colspan="2">Upper Not Shale</td></tr>
<tr><td>Garn 3</td><td></td><td rowspan="3">Not 2</td><td>Not 2.3</td><td rowspan="3">Not Sst</td></tr>
<tr><td>Garn 2</td><td></td><td>Not 2.2</td></tr>
<tr><td>Garn 1</td><td></td><td>Not 2.1</td></tr>
<tr><td>Not</td><td></td><td>Not 1</td><td colspan="2">Lower Not Shale</td></tr>
<tr><td rowspan="3">Ile 2</td><td rowspan="2">Ile 2.2</td><td rowspan="3">Ile 2</td><td rowspan="2">Ile 2.2</td><td>Ile 2.2.2</td></tr>
<tr><td>Ile 2.2.1</td></tr>
<tr><td>Ile 2.1</td><td>Ile 2.1</td><td rowspan="4"></td></tr>
<tr><td rowspan="3">Ile 1</td><td>Ile 1.3</td><td rowspan="3">Ile 1</td><td>Ile 1.3</td></tr>
<tr><td>Ile 1.2</td><td>Ile 1.2</td></tr>
<tr><td>Ile 1.1</td><td>Ile 1.1</td></tr>
<tr><td rowspan="2">Tofte 2</td><td>Tofte 2.2</td><td>Tofte 2</td><td>Tofte 2.2</td><td rowspan="2"></td></tr>
<tr><td>Tofte 2.1</td><td></td><td>Tofte 2.1</td></tr>
<tr><td rowspan="2">Tofte 1</td><td>Tofte 1.2</td><td>Tofte 1</td><td>Tofte 1.2</td><td rowspan="2"></td></tr>
<tr><td>Tofte 1.1</td><td></td><td>Tofte 1.1</td></tr>
</table>

Figure 11: Geological models from 2002 and 2006. As we see, in 2006 the Garn formation is re-named as Not Sst [Fawke, 2008].

The reservoir also contrasts significantly in thickness (figure 12). Amplified erosion to the north has roots the lower parts of the reservoir to shrink in thickness; this can in particular be observed in the Tilje and lie formations. In the south the reservoir width is estimated to be around 260 meters, while in the north it is about half of this. In the far NE of the reservoir an unconformity can be recognized as well; around 130 meters (measured from Not 2), this can be found between the Tilje and Tofte formations.

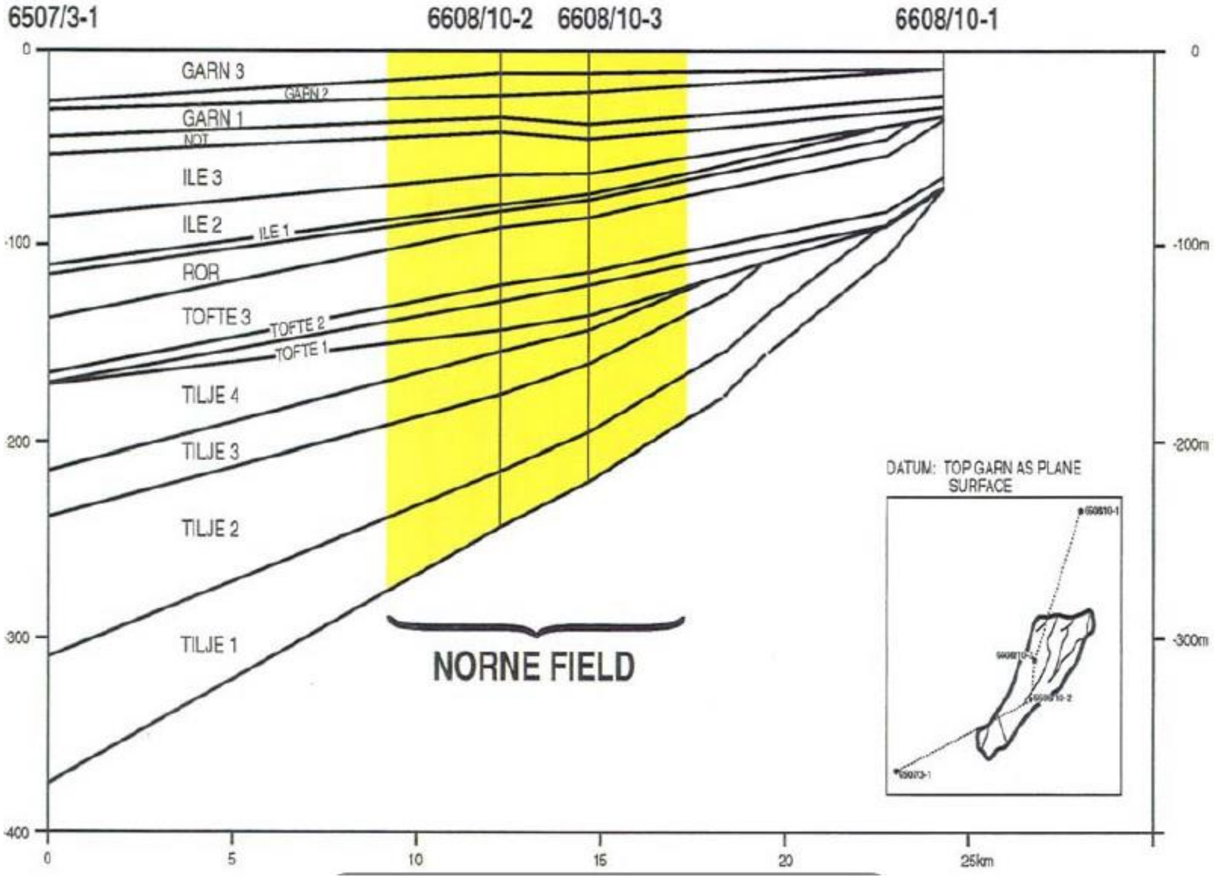


Figure 12: Illustration made from seismic mapping showing a cross-section through the reservoir zone Isochores (Statoil, 1994). From top Garn 3 and about 100 meters down, the Ror formation also can be seen.

4.1 Faults

Faults influence both vertical and horizontal flow in the reservoir, making them vital to identify and to model (Verlo & Hetland, 2008). Seismic data is an admirable tool for such identifications, and from the reservoir engineer's point of view; in the Norne field each sub-area of the fault planes has been allocated so-called transmissibility multipliers (a measure of fluid flow used in reservoir simulations). The zonation of the formations more defines fault sections in the reservoir. This way fluid flow can be geologically reliable with both permeability deviations in the formations and faults present in the reservoir (figure 13).In general these fault planes are functions of the magnitude of the grid blocks in the reservoir imitation model, fault zone with, matrix and rock permeability.

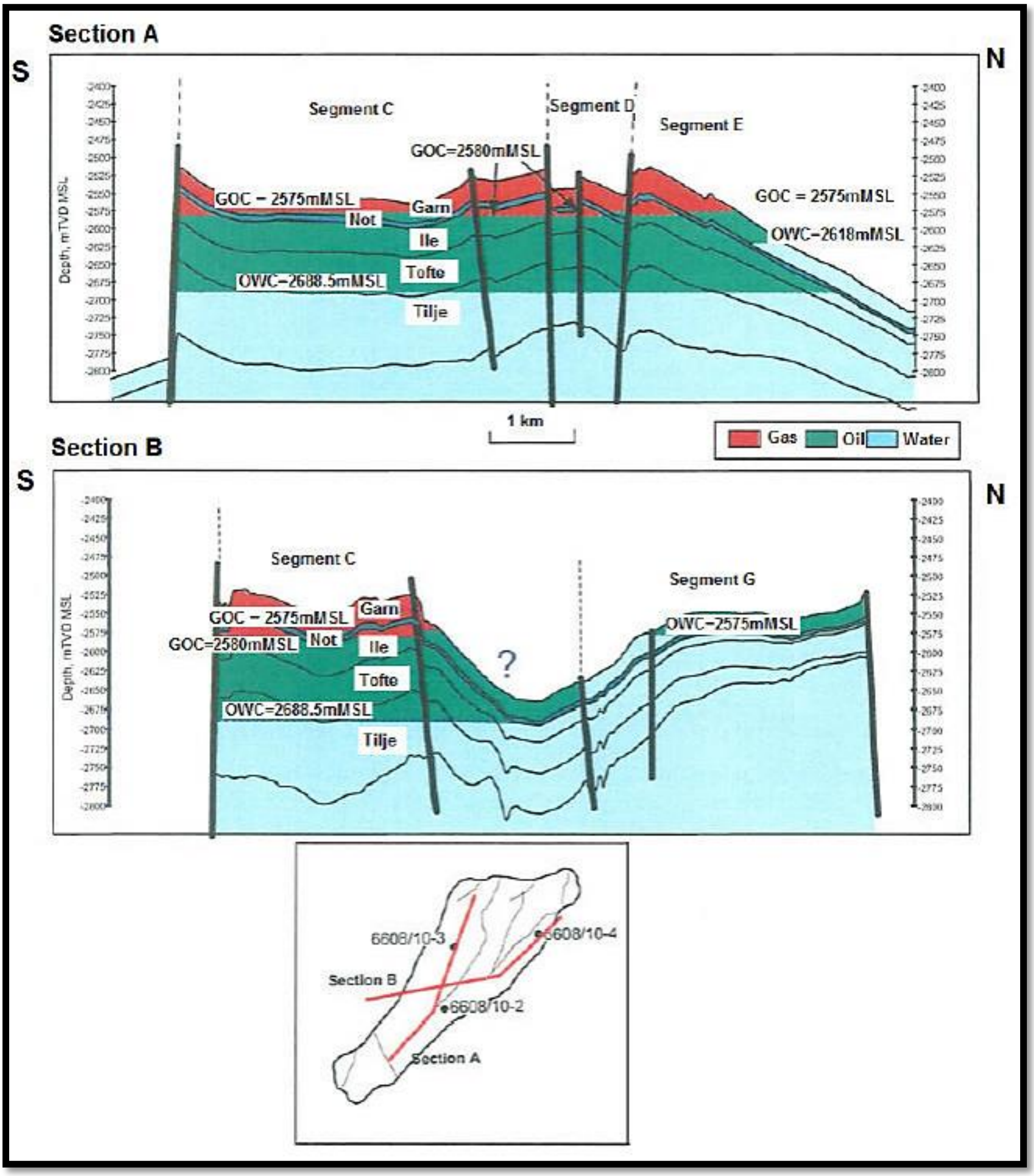


Figure 13: Two structural cross sections over the Norne Field, E-W (B) and N-S (A) displaying faults and fluid contacts [Statoil, 2001].

5 METHODOLOGY

5.1 Petrophysics

First the zone of interest is marked in the logs, then Petrophysical properties were calculated as Volume of Shale with the help of GR log and Porosity is calculated with of help of Neutron log, bulk density log and sonic log. Saturation of Water, Hydrocarbon Saturation, Permeability and Bulk Volume of Water is calculated using different techniques. To determine these Petrophysical properties the methodology adopted is discussed below:

5.1.1 Determination of volume of shale (Vsh)

Volume of shale was calculated with the help of GR log. First of all the maximum and minimum values of the GR curve are determined and then the GR readings at different intervals are taken in each zone marked. Then, with the help of this data, shale volume or gamma ray shale index (I_{GR}) is determined at different depth intervals with the help of the following formula (Schlumberger, 1974):

$$I_{GR} = \frac{\mathbf{GR_{Log}} - \mathbf{GR_{Min.}}}{\mathbf{GR_{Max.}} - \mathbf{GR_{Min.}}}$$

Where,

- GR_{log} = Log response in the zone of interest, API units
- GR_{min} = Log response in the clean beds, API units
- GR_{max}= Log response in the shale beds, API units

5.1.2 Total porosity

Porosity can be determined through different ways but we determined porosity through two ways (Schlumberger, 1974)

5.1.3 Density porosity

If the density log is used alone porosity can be determined using where (Hilchie, 1976).

$$\varphi_D = \frac{\rho_m - \rho_b}{\rho_m - \rho_f}$$

- ρ_m= matrix density (g/cc) constant 2.71
- ρ_b= log reading (g/cc)
- ρ_f = density of mud filtrate (g/cc) constant 1

Inaccuracies may occure when taking readings in evaporites or gas bearing formations. The lower density will predict porosity higher than the actual value.

5.1.4 Sonic Porosity

Since the sonic/acoustic log is one of the first porosity logs run porosity can be calculated from the sonic log using (Wyllie et al, 1956):

$$\varphi_s = \frac{\Delta T_{\log} - \Delta T_{mat}}{\Delta T_F - \Delta T_{mat}}$$

Where,

- $\Delta T_{\log}$ = log reading
- ΔT_{mat} = matrix travel time constant 47
- ΔT_F= fluid travel time constant 189

5.1.5 Effective porosity

Effective Porosity is determined by using following formula (Hilchie, 1978):

Effective porosity = Total porosity * (1-V_{sh})

Where,

- V_{sh}= Volume of shale

5.1.6 Water saturation

Water saturation is calculated with the help of Archie's (1942) equation

$$S_w = n\sqrt{\left(\frac{a}{\varphi^m}\right) \times \left(\frac{R_w}{R_t}\right)}$$

Where

- S_w= Saturation of Water
- φ= Effective Porosity
- m=2 Cementation exponent
- a= 1 (Tortuosity factor)
- n= 2 (Saturation exponent)
- R^w= Formation water resistivity
- R^t= Formation true resistivity

5.1.7 Hydrocarbon saturation

Hydrocarbon saturation is determined by the following formula (Schlumberger, 1974):

$S_H=1-S_w$

Where,

- S_H= Saturation of Hydrocarbon
- S_w= Saturation of Water

5.1.8 Bulk volume of water

Bulk volume of water is calculated with following formula (Morris and Biggs, 1974):

$BVW = S_w \times \boldsymbol{\varphi_E}$

Where

- BVW = Bulk volume of water
- φ_E = Effective porosity
- S_w = Water Saturation

5.1.9 Permeability

Permeability is determined by using following formula (Schlumberger, 1977):

$$\boldsymbol{K_e}=\left[\mathbf{250}\times\left(\boldsymbol{\varphi}^{\mathbf{3}}/\boldsymbol{S_w}\right)\right]^{\mathbf{2}}$$

Where,

- K_e= Permeability
- φ= Effective porosity
- S_w= Saturation of Water

5.1.10 Determination of lithology

The lithology is determined with the help of “N-D (Neutron porosity and density) Crossplot for mineral identification”.

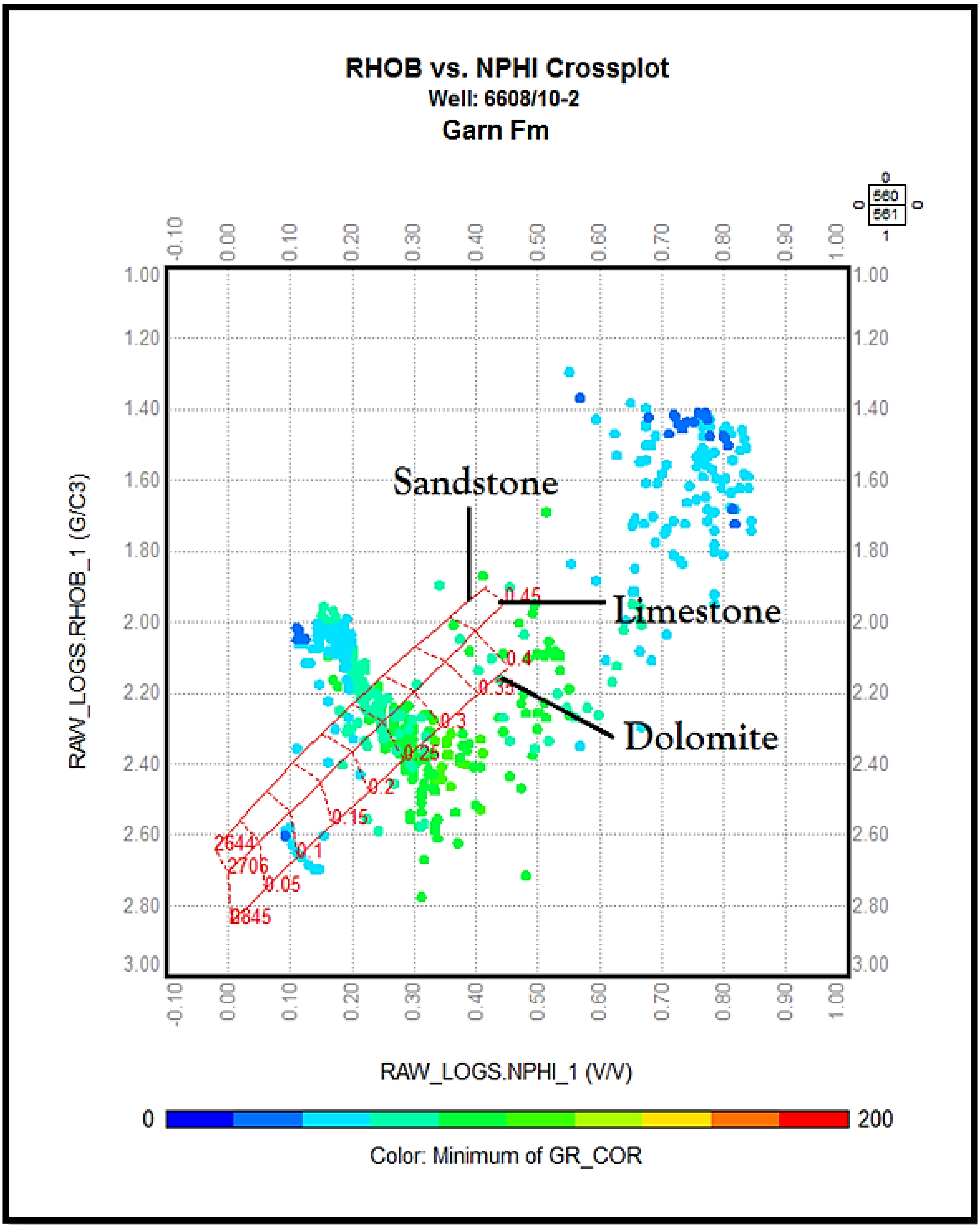


Fig 14: X-plot representing Garn Formation.

This is just an overview of Neutron density and porosity x-plot. It'll be futher explained in chapter 6.

5.1.11 Wells and Logs

Several wells have been drilled in the Norne Field. At the moment 46 of them are accessible at the FFN database. In this thesis I decided to use 2 of them to compare known lithology to the seismic construal. Being almost vertical and having checkshot data, the selected wells are 6608/10-2 and 6608/10-4.

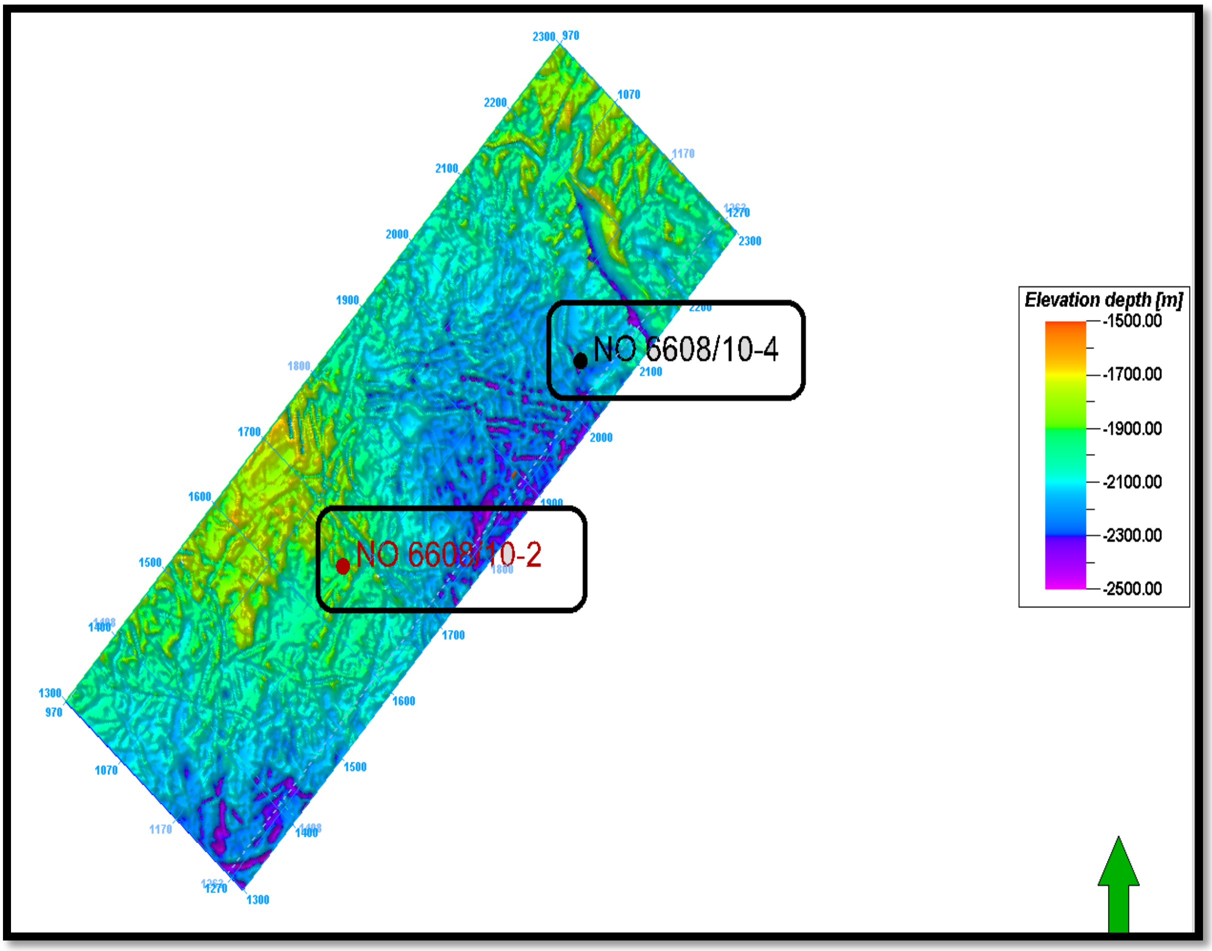


Fig 15: Location of well NO 6608/10-2 and NO 6608/10-4

5.1.12 Well6608/10-2

Well 6608/10-2 is a wildcat well situated fairly in the centre parts of the field at NS 7321933.62 and EW 457994.68 UTM (NPD). It was drilled in late 1991 to test the HC potential in the Garn and Ilie formations. A total of 3225 meters encountered jurrasic age, before reaching the depth, oil and gas were struck in the Lower-Middle Jurassic Sandstone. In the periods between 2590 to 2741 meters 6 cores at a total of 141.5 meters were encountered. These are the Are, Tilje, Tofte, Ilie and Not formation.

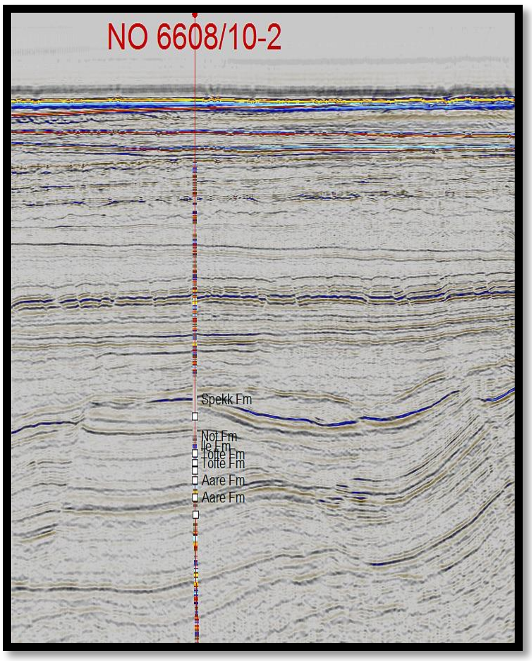


Fig 16: Well 6608/10-2 with formation tops.

5.1.13 Well6608/10-4

Well 6608/10-4 as well is a wildcat well drilled at NS 7324847.23 and 462006.74 UTM (NPD web pages). It was managed by Den Norske Stats Oljeselskap AS and was drilled from late 1993 to early 1994. The well aim was to prove oil growth in the Middle Jurassic sandstones; Garn formation confirm to have oil.

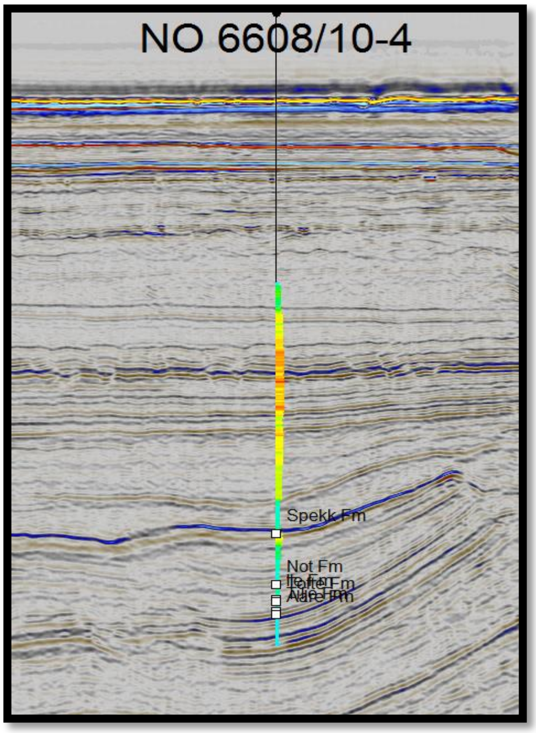


Figure 17: Well 6608/10-4 with formation tops

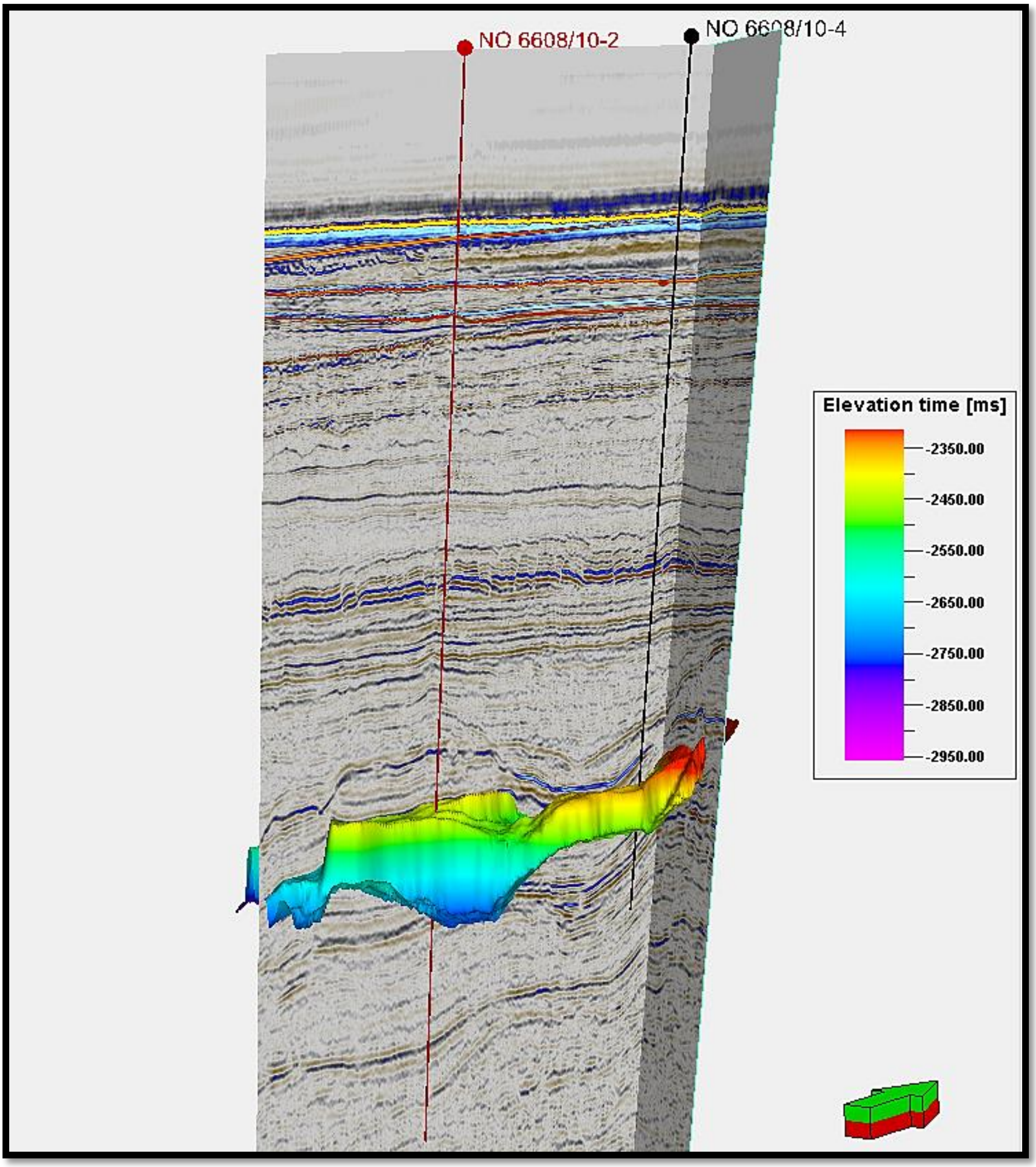


Figure 18: Zoomed out 3D view along wells 6608/10-2 and 6608/10-4. The Top Garn surface was later added for display purposes.

5.2 Seismic Interpretation Methodology

This part of the thesis is seismic interpretation which consists of two parts:

1- Interpretation of reflectors and faults (2D interpretation window)

Seismic lines interpreted were 14. Reflector and Faults (Major and minor) were interpreted.

Principal reflectors were:

- Top Garn
- Top Ile
- Top Tofte
- Top Åre

Secondary reflector (only in 2D interpretation window) were Top Res-Cap I, II & III, Top Spekk and Top Tilje

The interpretation focuses on main geological features of reservoir.

2- 3D interpretation of horizons

- Top Garn
- Top Ile
- Top Tofte
- Top Tofte
- Top Tilje
- Top Åre

Create 3D surfaces from interpreted horizons:

- Top Garn
- Top Are

The 3D interpretations focuses on techniques needed to construct these geological features from a practical point of view.

In the end I will conclude interpretations; displaying the geological features in 3D.

Important note: By 2D interpretations, I meant the interpretation of the selected 14 seismic lines in the 2D interpretation window.

The interpretation method I have applied in this thesis is an integrated 2D (2D interpretation windows) and 3D approach; through which I can cross check my results.

First of all I selected 14 seismic lines in petrel to:

- Cover the field
- Develop an initial understanding of the sub surface geology
- Correlate reflectors to formation top names from wells
- Interpret minor and major faults to get an idea of how the reflectors behave throughout the faulted structures
- Interpret the reflectors

For consistent interpretation understanding of seismic lines in 2D interpretation window is important, Representative seismic lines can reveal major structures as well as the focus can be on the reflectors of interest . In contrary, it is very hard to get an overview or to find a suitable interpretation starting point just by rotating and flipping through a seismic.

I useall these techniques when interpreting faults; in a faulted area a reflector might split in half and located relatively a bit far way. The computer doesn't necessarily recognize the geologically correct way to deal with such conditions. Due to poor seismic data quality in particular parts of the field, weak amplitudes might also have to be manually interpreted later; seeded interpretation between already 2D interpreted reflectors in 3D might be an efficient technique. The three interpretation techniques are all done in both 2D and 3D to ensure both efficiency and quality. Furthermore all interpreted reflectors are given a designated color and assumed to be the top surfaceof a correspondings.

When I start interpreting the second seismic line, I will discuss seismic tie; which makes up the first building blocks for the 3D horizons as reflectors are typically seen as thin horizontal strips in the seismic cube. In a particular line, 2D seismic ties will show up as markers displaying whether crossing and intersecting lines have the same reflectors or not (figure 5.1.2). I want to do this right in 2D interpretation because it can be a tedious trial and error procedure to get the ties right in structurally challenging areas; this has to be as correct as possible before starting the 3D horizon interpretation.

At the same time I select the 14 seismic lines

- Ensures the 14 seismic lines covers the field in a representative manner
- Create specific lines for additional profiling

- Efficiently display well placements and surfaces as they are created
- Keep track of in- and cross lines numbers and field coordinates
- Keep track of the directions (north, south, east and west) when interpreting, describing and discussing results
- a rough lateral correlation to the interpretation; this lets me define some geological features at an early stage

Major faults and corresponding fault blocks marks the end of the seismic interpretation in this thesis. Results from this will further be discussed in chapter (conclusion). As the 2D and 3D interpretation itself begins, some of these steps will be described in detail:

- Intersection 10-2/10-4 (the first line to be interpreted)
  - Correlation of formation top names to the seismic reflectors
  - General fault and reflector 2D window interpretation techniques

- Top Garn horizon
  - General horizon 3D interpretation techniques

- Top Melke horizon
  - Detailed studies of how the reflectors behave throughout the seismic volume using intersection lines. This is to confirm the faults outlined by the interpretation of Top Garn.

Once again, in 2D I start to define geological features (identify the elements). In 3D I focus on practical interpretation techniques which are to build the elements. In next chapter I combine my results from the 2D and 3D, displaying the features in 3D.

5.2.1 The Surface Map

14 seismic lines have been selected for the interpretation (figure 19). The base map displays accordingly and in general four groups can further be described:

- Seismic lines 1 to 3: Well-intersecting lines
- Seismic lines 4 and 5: Discussed profiles from literature
- Seismic lines 6 to 8: lnlines
- Seismic lines 9 to 14:Crosslines

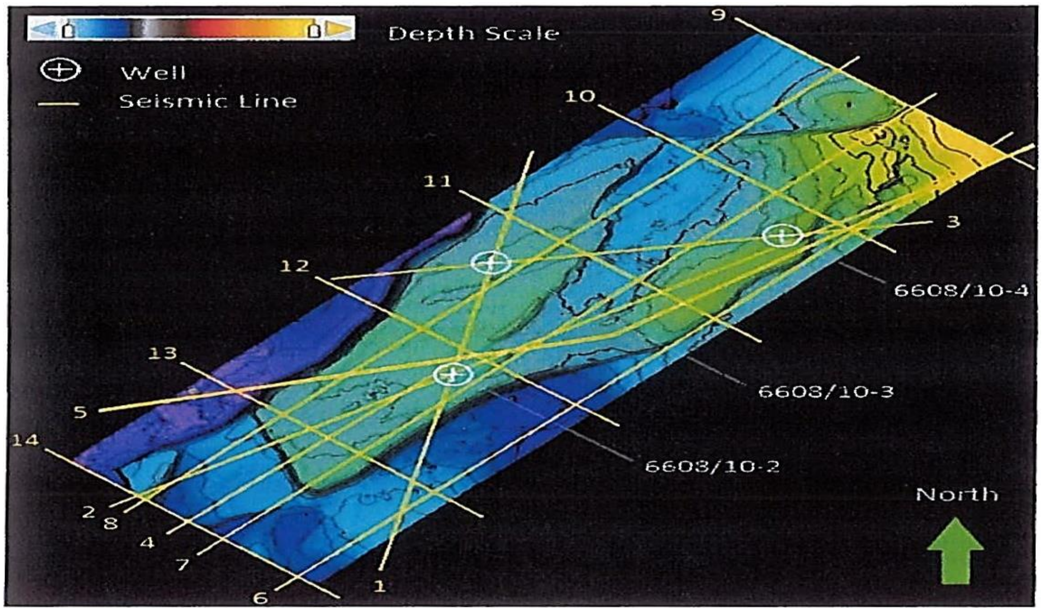


Figure 19: Map from above displaying the 14 seismic lines (yellow) and the 3 wells (white) over the Norne Field. The arrow points towards north (green) and a resulting. surface map (multi-coloured, hot colours are elevated is at reservoir depth. For practical reasons this surface also is included. in the general description of the selected lines.

5.2.2 Well-intersecting lines

Seismic lines 1, 2 and 3 intersect wells 6608/10-2, 6608/10-3 and 6608/10-4 respectively (table 4.2.2.1). These wells laterally cover a representative area of the Norne Field (figure 19). The wells are nearly vertical making them suitable for this purpose. In particular well 6608/10-2 is used for correlating the seismic volume to known lithology from logs. Wells 6608/10-2 and 6608/10-4 has correlated top formation names with corresponding two-way travel times from check shots and log data. Therefore intersection 10-2/10-4 is the first line to be interpreted.

Table 5.2.2.1

Seismic line	Name	Description
1	Intersection 10-2/10-3	Intersects wells 6608/10-2 and
2	Intersection 10-2/10-4	Intersects wells 6608/10-2 and
3	Intersection 10-3/10-4	Intersects wells 6608/10-3 and

Table 5.2.2.2

Seismic line	Name	Description
4	Section A	Discussed profile from literature
5	Section B	Discussed profile from literature

5.2.3 Inlines

Seismic lines 6, 7 and 8 characterize the classic grid approach (table 5.2.3.1). The purpose of selecting these inlines is to laterally cover the seismic volume so the faults and reflectors can be consistently interpreted across the Field .When interpreting horizons further inlines can be interpreted, but this also depends on the geology; other lines may be more suitable in various situations. These inlines are intended to be starting points for the interpretation.

Table 5.2.3.1

Seismic line	Name	Description
6	Inline 1070	Inline grid
7	Inline 1170	Inline grid
8	Inline 1270	Inline grid

5.2.4 Crosslines

Seismic lines 9 to 14 makes up the rest of the grid in a similar way as for the inlines (table 5.2.4.1). Running orthogonal to the inlines, the crosslines also are meant to laterally cover the Norne Field in a representative way. An important part of the interpretation is the seismic tie between in and crosslines. This implies that each time an interpreted inline runs through a crossline, we should see reflector joints indicating their corresponding position in the crossline (and the other way around). As for the inlines described, these crosslines are also intended to be starting point for the Int erpretation.

Table 5.2.4.1

Seismic line	Name	Description
9	Crossline 1300	Crossline grid
10	Crossline 1500	Crossline grid
11	Crossline 1700	Crossline grid
12	Crossline 1900	Crossline grid
13	Crossline 2100	Crossline grid
14	Crossline 2300	Crossline grid

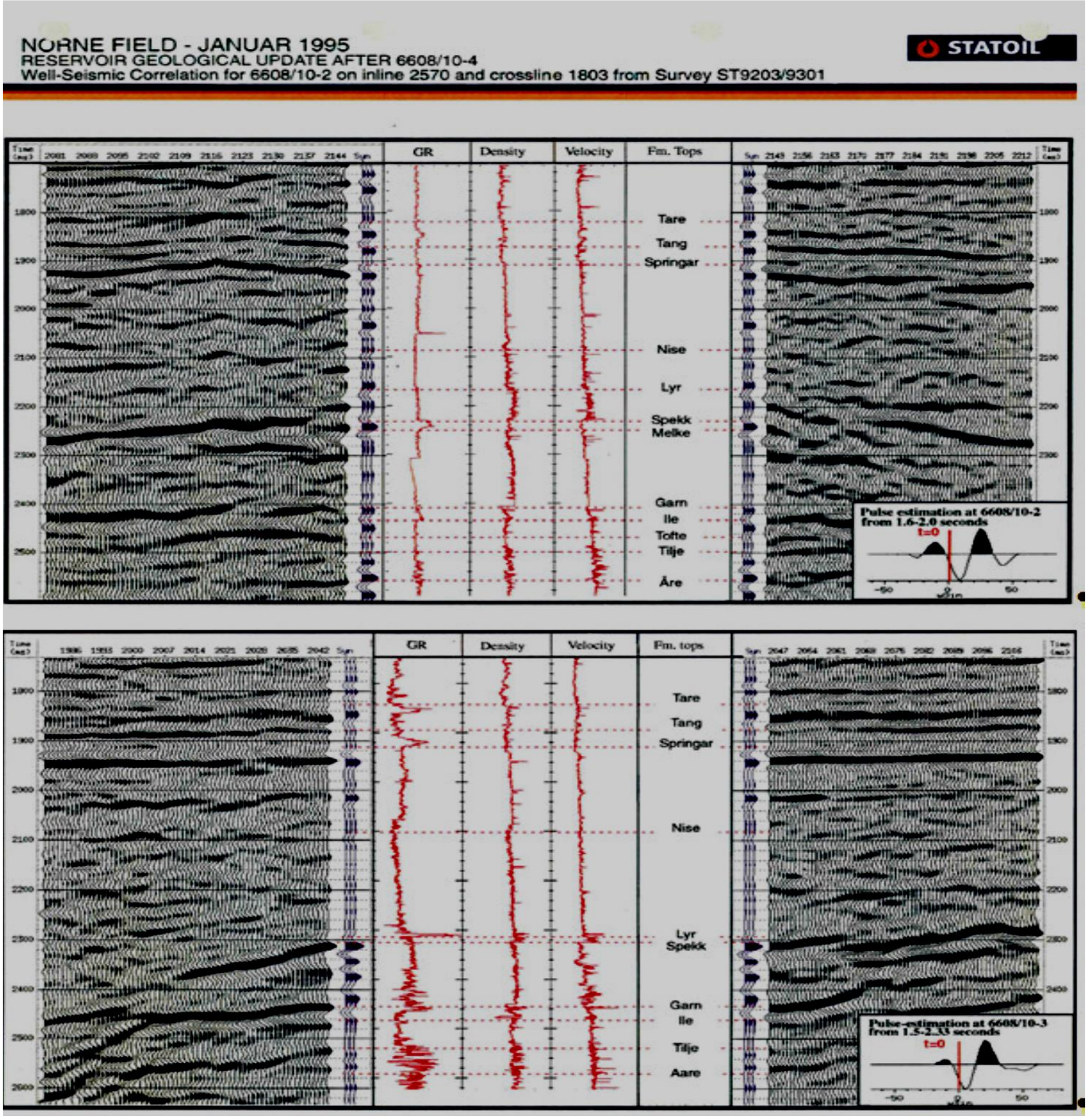


Figure 20: Statoil reference depths for formation tops

6 Interpretation

6.1.1 Seismic Line 2: Intersection 10-2/10-4

Intersection line 10-2/10-4 is the first seismic line to be interpreted. Wells 6608/10-2 and 6608/10-4 have correlated formation tops with corresponding TWT; the reservoir is located at 2577 .72 and 2566.74 TWT ms respectively (figure 21).I first interpret 4 major faults between the two wells (figure 22). This way, the faulted formations become more visible, as reflectors often can be difficult to interpret across faults. Focusing on the area between the two wells, I interpret the two strongest reflectors to be Top Spekk and Top Garn respectively.

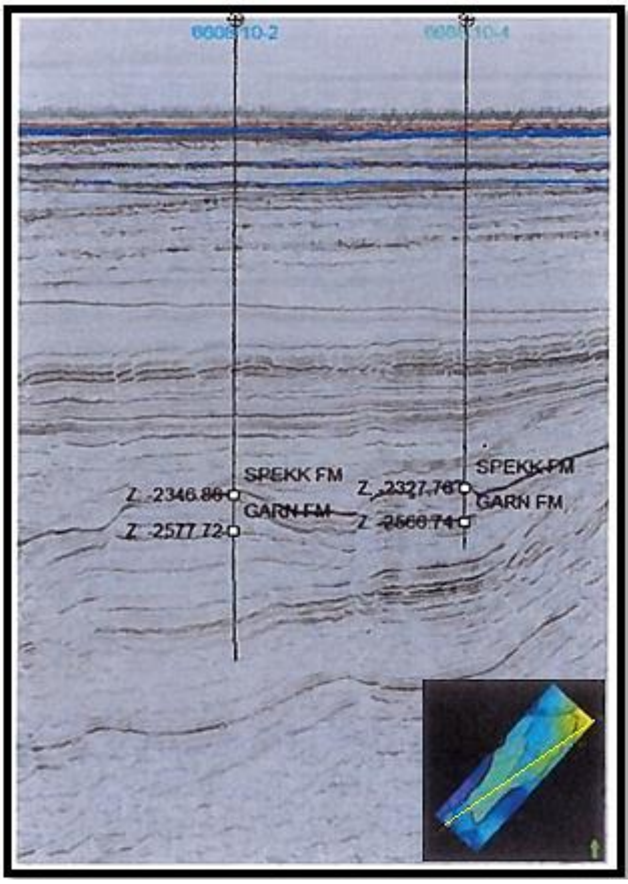


Figure 21: Left: A full view of the subsurface from the sea floor (red reflector) to top reservoir (GARN FM). Top Spekk Is found at 2346.86 and 2327.76 TWT ms in we s 6608/10-2 (blue) and 6608/10-4 (turquoise) respectively; this is the principal seal of the reservoir. Right: Intersection 10-2/10-4 displayed on the surface map.

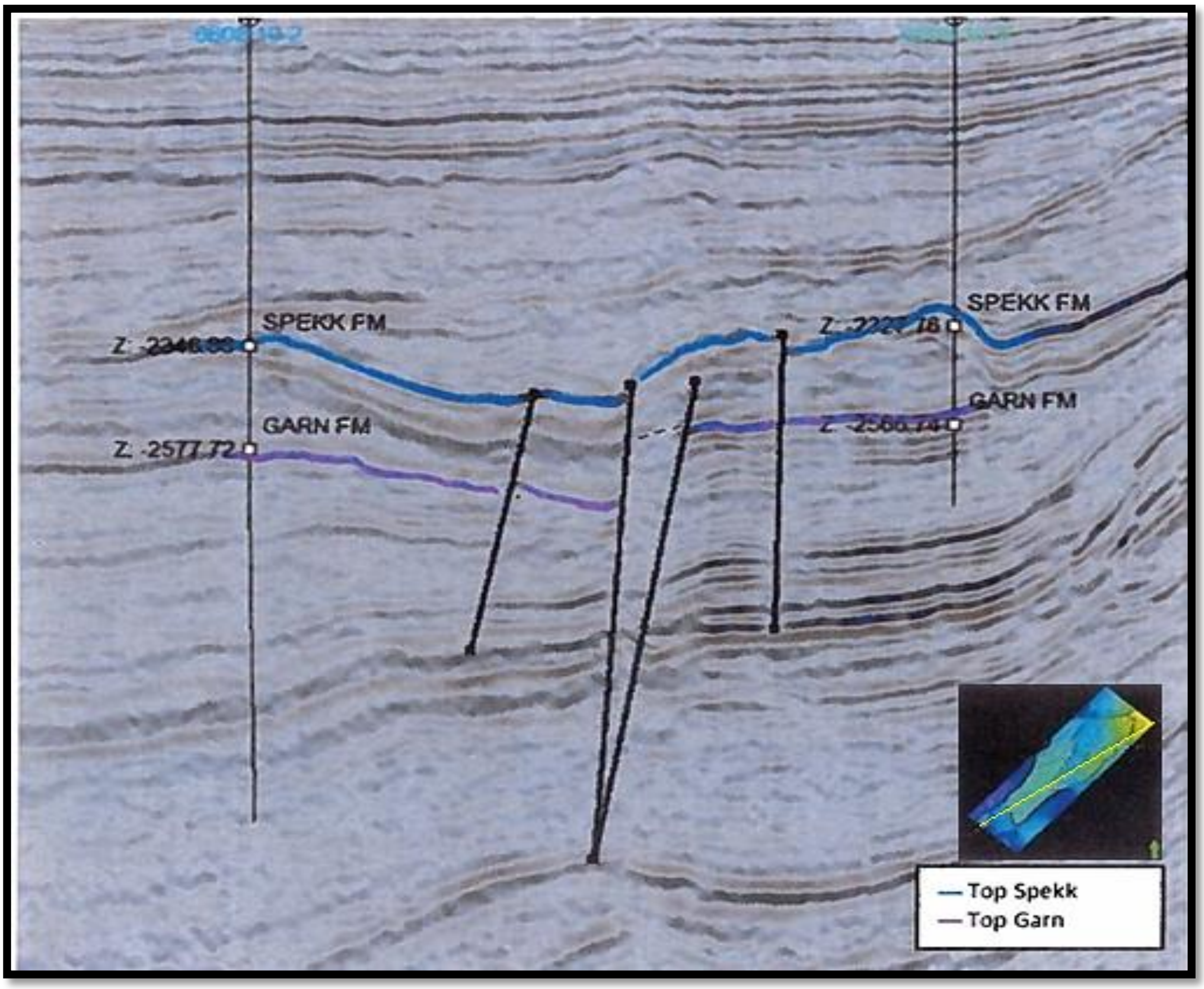


Figure 22: The interpretation of the Top Spekk (blue) and Top Garn (pink) reflectors was first done by guided tracking to get smooth lines across the amplitudes. Where it seemed appropriate, I then went over the reflectors manually to get a more smooth interpretation. However to ensure that con tinuous reflector-segments do not overlap faults, I leave a small space between the reflector and the fault. In between the two largest faults a more diffuse area can be seen; this typically would be an area for manual interpretations as well. Chances are that the two largest faults actually outline a fault plane; one fault cuts the seismic line at an angle (stippled black line). We also note that the top names (white squares) do not exactly fit with the reflectors; logs, cores and an overall visual consideration of the most likely cor responding reflector has to be done.

At least 2 fault blocks can be observed, separated by a more scatter area. This could be a fault plane, revealing single fault seen as it cuts intersection 10-2/10-4 at an angle. As we see, the reflectors might continue at another dipping angle in. All faults seem to have very sharp apparent dips, imply that we are looking away from the strike (normal faults typically have dips around 60 degrees). I then continue to interpret the rest of the reflectors between wells 6608/10-2 and 6608/10-4 (figure 23). Top lie is found directly beneath Top Garn and Top Åre is the lowermost formation.

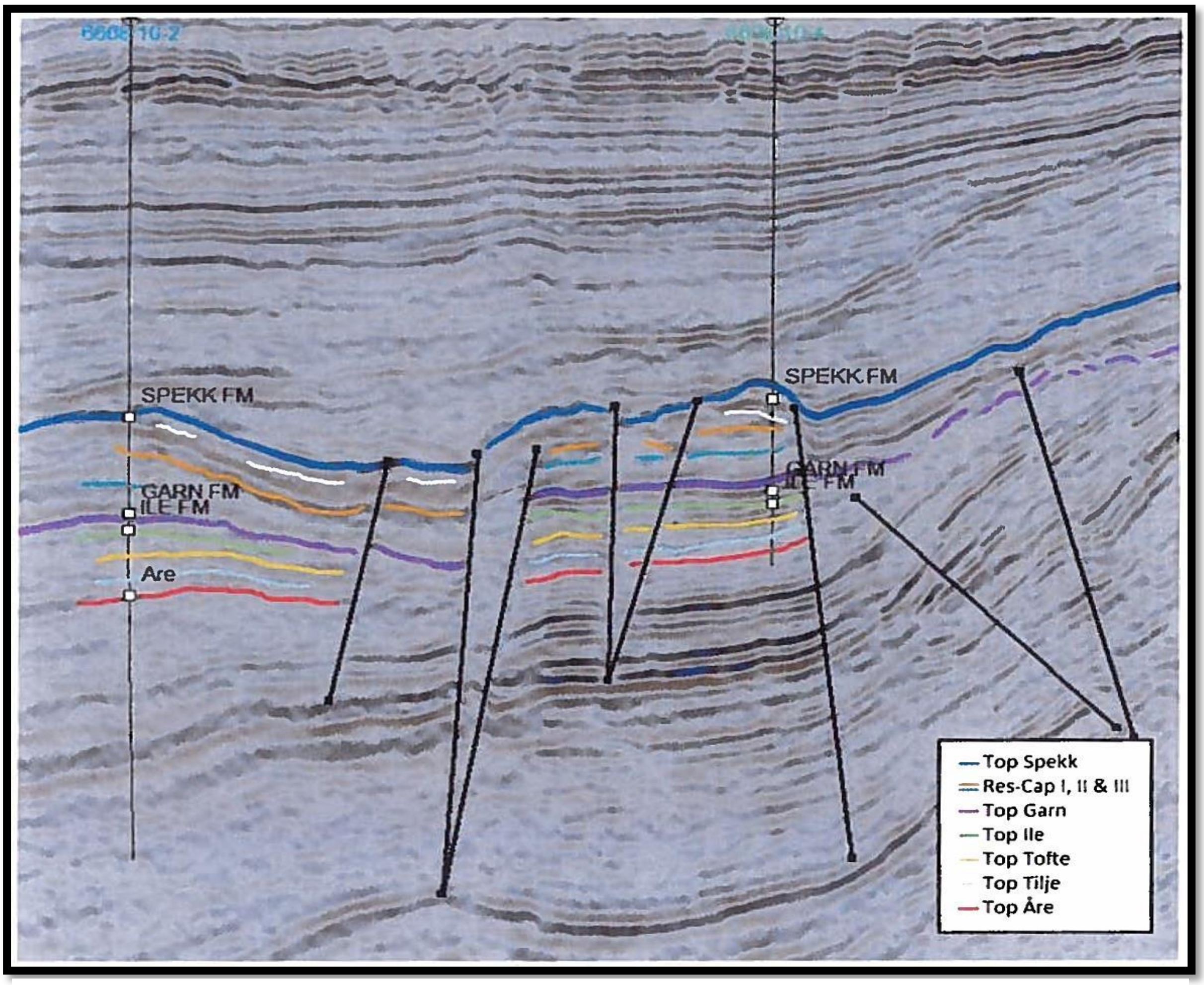


Figure 23: In addition to Top Tofte (yellow) and Top Tilje (light blue) three reflectors that might correspond to i.e. top Melke and Top Not can be seen (white, orange and blue green). These reflectors are assumed to represent overlapping formations and minor segments.However, as their presence influences the 6 objective reflectors, still interpret some of them for practical reasons. NE of well 6608/10-4 (to the right) we see that the Garn Formation probably has some minor faults; In addition four more faults are added. As previously discussed, two of them may form a fault plane.

Finally, interpreting outside wells 6608/10-2 and 6608/10-4 several faults become visible. To the NE we have lots of minor faults; to the SW the faults seem fairly larger. The assumed minor faults may actually be explained by resolution issues or other seismic artifacts; they are visualized in the intersection 10-2/10-4 because these features cut the reflectors and form what seem to be minor blocks. However the second largest faults in between the wells is interpreted to be fault D-East. To the SW of well 6608/10-Z I also interpret fault C-South.

As this complete the first steps in the interpretation, I now define two major fault blocks outlined by the interpreted faults; block C and block G. The focus on these faults and corresponding fault blocks could change throughout the interpretation if their presence turned out to be insignificant for the major parts of the reservoir; however one of the objectives is to interpret such principal features. These Interpretations thus defines a starting point.

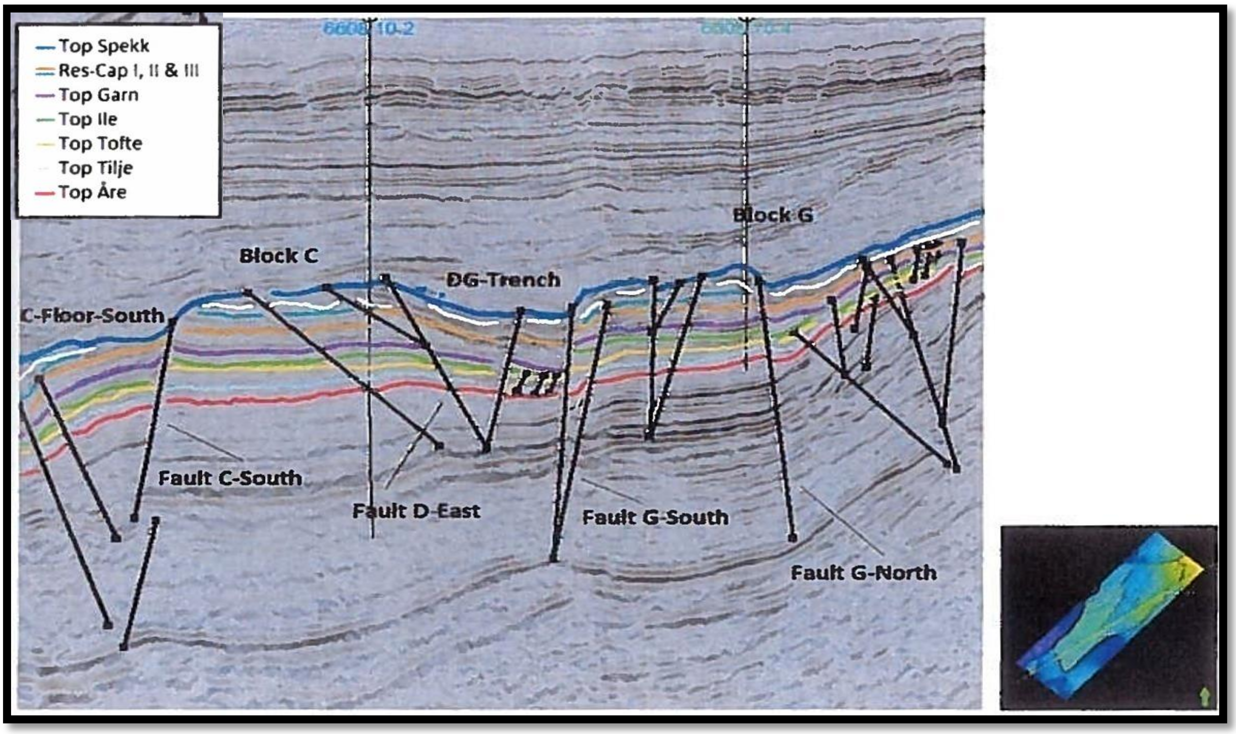


Figure 24: The complete interpretation of intersection 10-2 and 10-4. As we now see,two large fault block interpreted as block C & G. Faults that outline these blocks from SW to NE are C-south and G-west.

6.1.2 Seismic Line 11: Crossline 1700

The second line I interpret is crossline 1700. This is seismic ties to intersection 10-2/10-4 (figure 25).

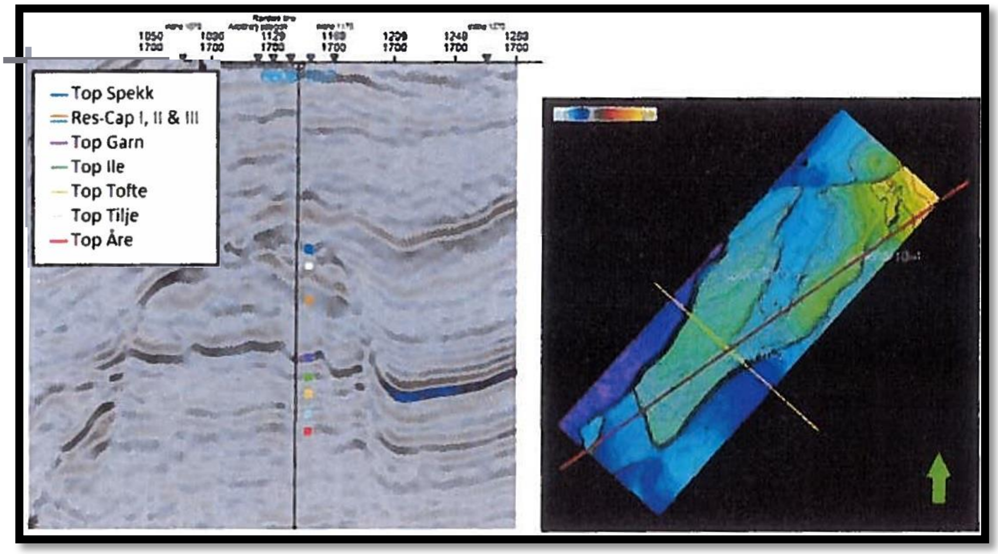


Figure 25: Left: Seismic ties between crossline 1700 (displayed seismic line) and intersection 10- 2/10-4; the Interpreted reflectors from intersection 10-2/10·4 (colored squares) are clearly corresponding to the most visible reflectors in crossline 1700. Also, at the top of this image we see how other lines intersect crossline 1700 (green triangles). Right: On the surface map we see how intersection 10·2/10-4 and 1700 crossline define a central and natural junction in the reservoir. With these two seismic lines correctly Interpreted a large area consisting of formations and larger structures can be outlined.

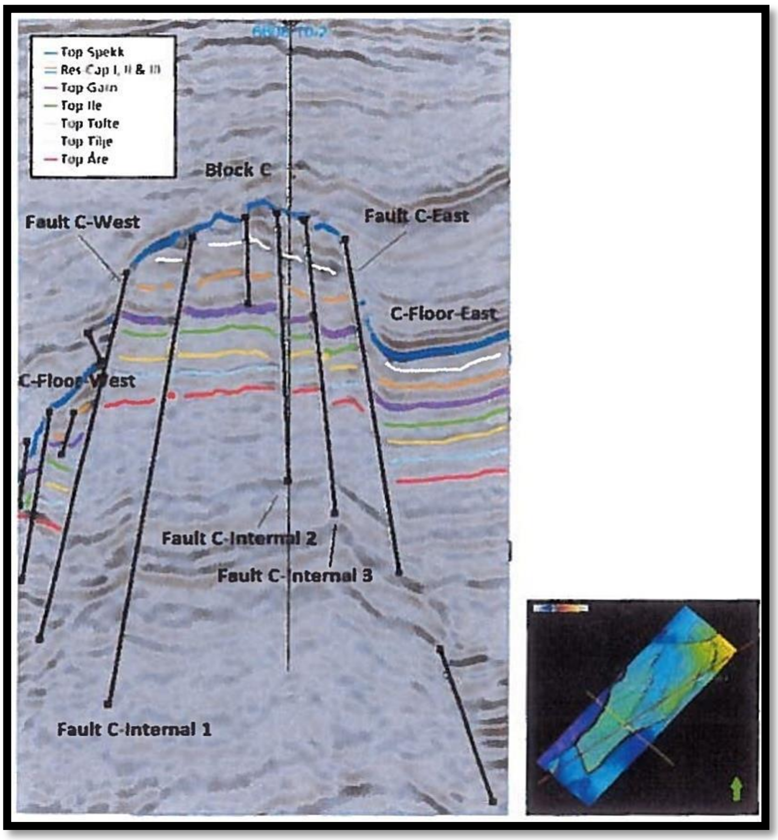


Figure 26: Left: Fault C-west and C-East defines three areas; a "messy" floor to the NE (C-Floor-west), block C In the centre and a more layered floor to the C-Floor East. Internal faulfong of this block is Interpreted as C-internal1, 2 and 3.Right: Surface map displaying how intersection 10·2/10·4 (red line) and crossline 1700 (yellow line) relate.

I get a good tie between Intersection 10-2/10-4. This makes it easy for me to at least interpret the related reflectors. As two intersecting 2D lines define a -3D horizon, the seismic tie between intersections 10-2/10-4 will let me interpret some key horizons in the reservoir. Provided that well-tie is correct (with corresponding lithology), the interpretation of 3D horizons have already begun. Crossline 1700 also is easily centered around well 6608/10-2 (figure 26).

Homogenous faults characterize crossline 1700. On both sides of fault block C, fault C-west and C-East is interpreted. Are Formation at the bottom is believed to be the source rock for the reservoir, some of the internal faults within block C are highly important as these permits flow and communication between reservoir zones and compartments. For practical reasons, in this clear seismic line therefore I interpret the 3 prime internal faults to be C- internal 1, 2 and 3 respectively. The interpretation of the reflectors within the block C is straight forward. SE of fault C-west a layered floor can be seen; for now it is interpreted relative to Top Spekk and Top Garn under the supposition that the formations are corresponding to the well tops described. However such assumptions typically are accustomed as the interpretation develops, as more seismic ties are added to the lines. NW of fault C-East is an example of this; the reflectors are cluttered and hard to interpret and will most likely evolve later on.

6.1.3 Seismic Line 4: Section A

The general correlation of reflectors to literature, Section A reveals several faults (figure 27). Mainly above Top Garn a sequence of minor faults can be seen. Again, these are possible minor faults that will not be further described in this thesis; however they are mentioned and interpreted in Section A. The largest fault in the SW splitting the formations in two clear sections is interpreted as C-South. Around fault C-South some minor faulting can be observed; this may be further investigated later on. North of well 6608/10-2 two very attractive faults are interpreted as D-lnternal 1and E-West. The reason this is interesting is that I now start to see how these faults outline the segments we have already discussed in the research. These major structures are closing in on the key interpretation objectives of the thesis. The D-internal 2 fault is considered to be a little less prominent, but still is interpreted. Furthermore fault D-Internal and E- West define block D and E. SW of fault C-South the reflectors seem to pan out in what is interpreted as C-Floor-South. NE and north of fault C-South, the reflector interpretation is straight forward with small difficulties.

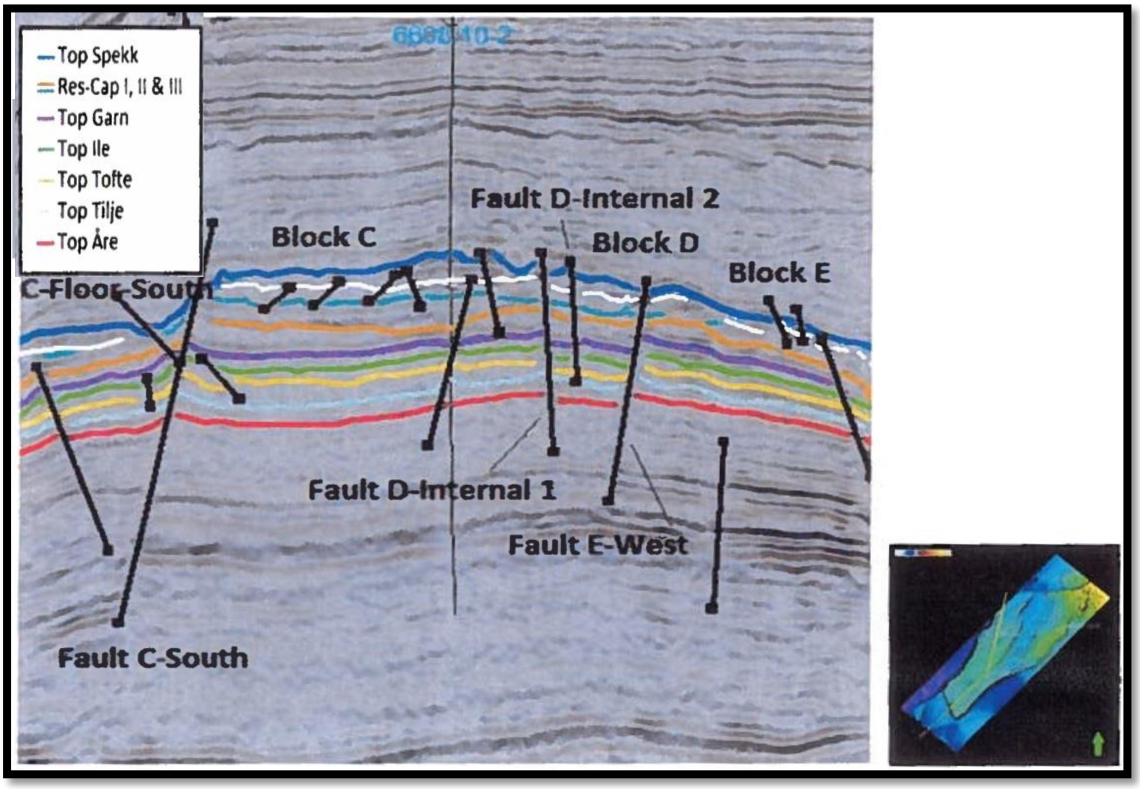


Figure 27: left: Fault C-South splits C-Floor-South from block C, D and E. Block D and E is further outlined by fault D-internal and E-West. In general, the interpretation of the reflectors in Section A does not appear to be too difficult. Right: Surface map displaying how Section A is split in two directions.

6.1.4 Seismic Line 7: In line 1170

At first look inline 1170 reveals large and different structures (figure 28). Now that we have recognized some of them, the apparent reason for this is that inline 1170 cuts through the whole field, stretching from the block C in the SW to a layered sequence in the NE. A heavily faulted section can be seen in the centre part of the image, still they are located somewhat deeper in the reservoir and do not murky the reflectors. The largest fault in the group clearly splitting the Top Garn reflector is interpreted as C-North. Additional to this NE, I interpret the G-South and G-North faults; defining the G block in between. NE of G-North a small floor can be seen, however this will not be discussed further here. In the southern parts of the G block, the Top lie seem to be a bit missing, even though it is too early to say whether it is completely gone, just thinner, wrongly interpreted or not seen by the seismic. Same goes for Top Tofte in block G; maybe this is the erosional surface. Otherwise, the rest of the reflectors seem alright.

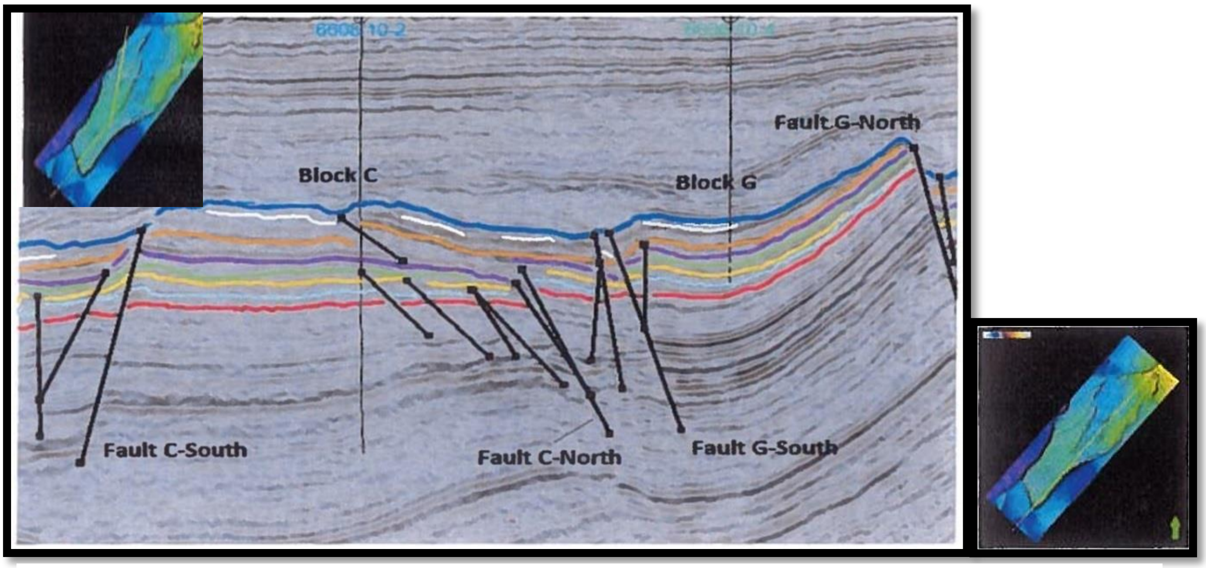


Figure 28: Bottom: The C-South, G-South and G-North faults define the C and G blocks; NE a layered sequence can be seen as the latter. Top: Surface map displaying how inline 1170 cuts through the entire field

6.1.5 Seismic Line 12: Crossline 1900

As with crossline 1700, crossline 1900 has some of the same fault features; they cut deep and are not too muddled (figure 29). The major fault apparent fault dip trend seems to be from NW to SE top down, with matching visible strike planes in the SW-NE direction. However some minor faults seem to be leaning in the opposite direction, in turn maybe defining minor fault blocks. Interpreting the bigger faults from NW to SE, I have D-West, E-East, D-lnternal, D-East, G-West and G-East with related fault blocks E, D and G. In between block D and G a trench is interpreted as the DG- Trench. Although a more thorough study of the internal faults in the E, D and G blocks has to be carried out in order to create suitable reservoir zones and compartments; for now these are interpreted in 2D.

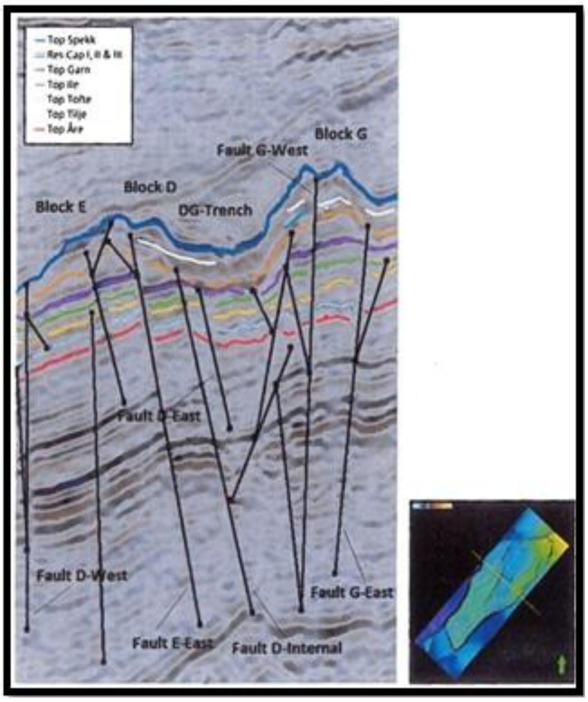


Figure 29: left: From NW to SE, I have D-West, E-East, D-lnternal, D-East, G-West and G-East with corresponding fault blocks E, D and G. Some of the larger faults may be studied later as they govern zonation and flow. Right: Surface map displaying how crossline 1900 cuts through the central parts of the field.

6.1.6 Seismic Line 1: Intersection 10-2/10-3

Intersection of 10-2/10-3 symbolizes suitable seismic tie-check . As we see, the key reflectors Top Spekk, Top Garn and Top Are appear to correlate well. In between these reflectors, Top lie, Top Tofte and Top Tilje also seem to represent logical interpretations. By looking at Intersection 10-2/10-3, the strong reflector Top Garn outline some of the faults and subsequent fault blocks already discussed.

Question is this, what makes Intersection 10-2/10-3 an interesting line, is it cuts the in- and crosslines equally at an angle of about 45 degrees; lets us see the features from another perspective (figure 30). In general, most of the reflectors are fairly easily interpreted.

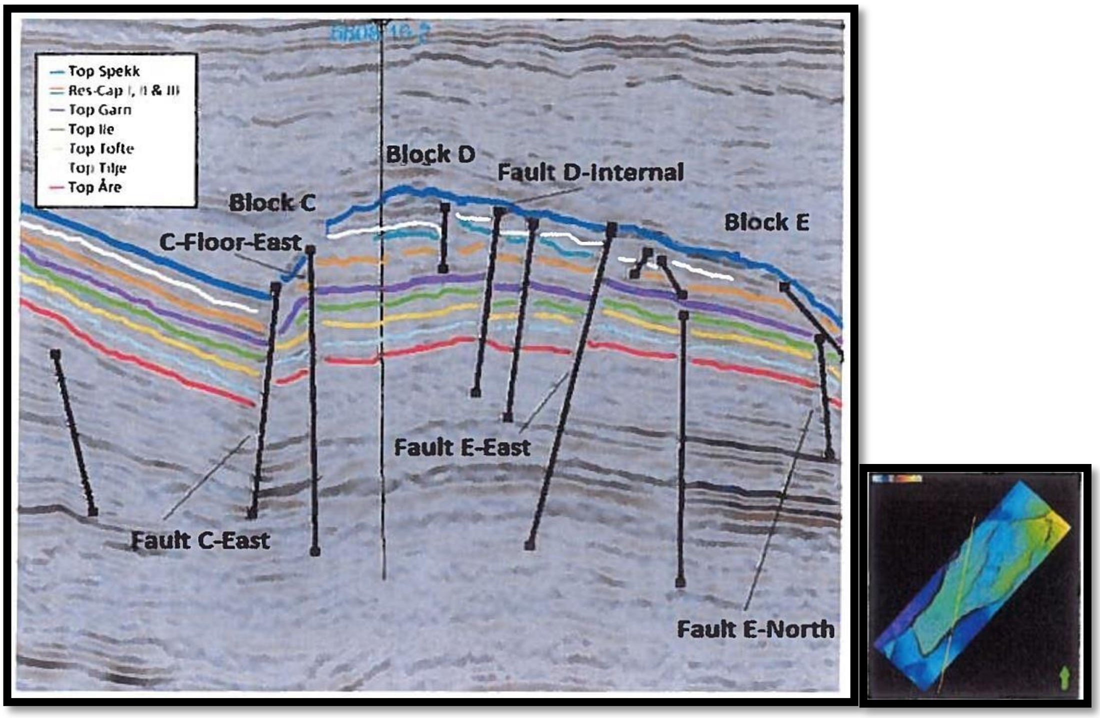


Figure 30: left: From South to North; the C-Floor-East can be recognized as an inward dipping sequence towards what is interpreted as the C-East fault. Further up north the D-Internal and E·East faults can be seen. In addition, I also interpret the E-North fault. Right: Surface map displaying the 45 degree angle trademark of intersection 10-2/10·3.

6.1.7 Seismic Line 10: Crossline 1500

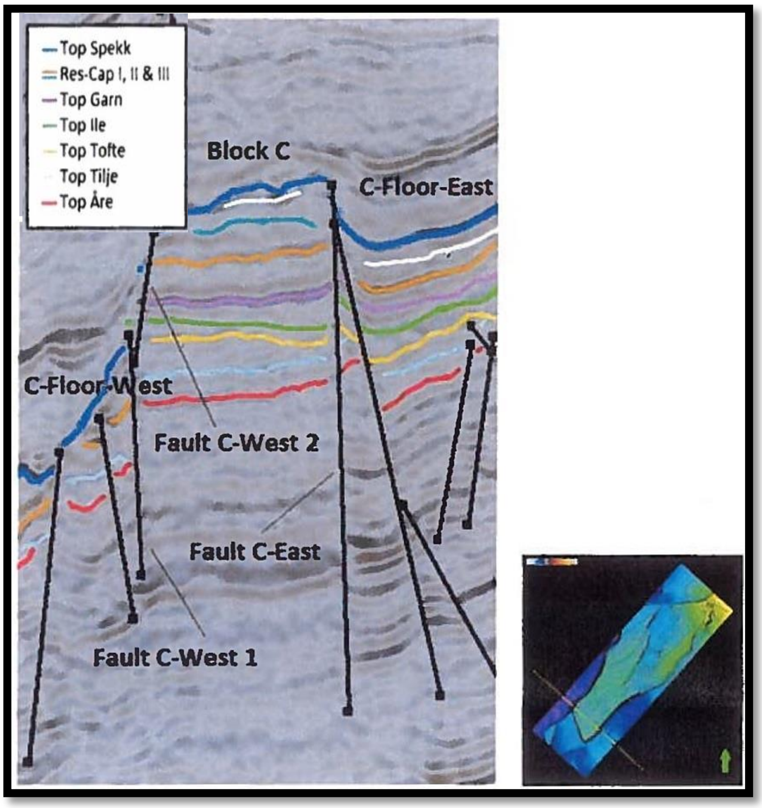


Figure 31: Left: From NE to SE; the C-Floor-West, the C-West 1and 2 faults. The C-East fault and C-Floor-East Is Interpreted. Right; Surface map displaying crossline 1500 cutting through the southern parts of the C block.

Crossline 1500 supports the features interpreted on crossline 1700 and crossline 1900 (figure 31). From west to east the characteristic is messy C-Floor-West bordering the C-West fault. Still, as major faults like the C-West fault in fact may pretty consists of faulted zones and bands, probability is that we see two sub-faults, here interpreted as C-West 1 and 2. Depending on the objectiveof the interpretation; creating a geological model such minor fault segments like these may have to further study. When interpreting fault planes in 3D, a general rule is first to make them as simple as possible and then later on try to shape them as realistic as possible without complicating the model. Curve-shaped listric faults could be an example of this. Here, the interpretation of two such closely located faults seems right as these probably will merge in the emerging 3D topography. Some of the reasons behind this idea will also be discussed in the next chapter. To the SE maybe a fault plane is seen, in either case interpreted as being the C-East fault. Far SE we once again have the C-Floor-East with moderately well organized and layered reflectors. Excluding the C-Floor West, most reflectors are relatively straightforwardly interpreted.

6.1.8 Seismic Line 8: lnline 1270

lnline 1270 reveals the curve shaped nature of the C-Floor-East, seen from the side. With minor faulting in the south (not relevant for this thesis because they are found outside the main reservoir segments), the middle-south section is characterized by strong and continuous reflectors (figure 32). Very middle of inline 1270 a rather large fault is interpreted as being G-South/West. The reason this fault has this unclear name, is that at this point I cannot say for sure whether this fault is part of the G-East fault or if it represent a minor fault across the southern part of the G block. If we look at the opening reflectors around this fault compared to the faults in the SW parts of the line, they are not greatly separated at all. Thus chances are this is not a block-defining fault. Situated east of the G block, several minor faults can be seen with apparent fair dips implying their fault plane strikes to be associated somewhat in NE-SW direction. This assumption is made on the basis that these typically would be normal faults having around 60 degrees dip; if we see them like this in the seismic line, we maybe looking at the corresponding fault blocks directly from the side. However, as with the faults in the SW part; these also are located outside the main reservoir blocks, making this seismic line a reference. It helps us to understand the nearby features as well as the ties are important for 3D horizon interpretation. In general, the reflectors are not too complex to interpret in inline 1270.

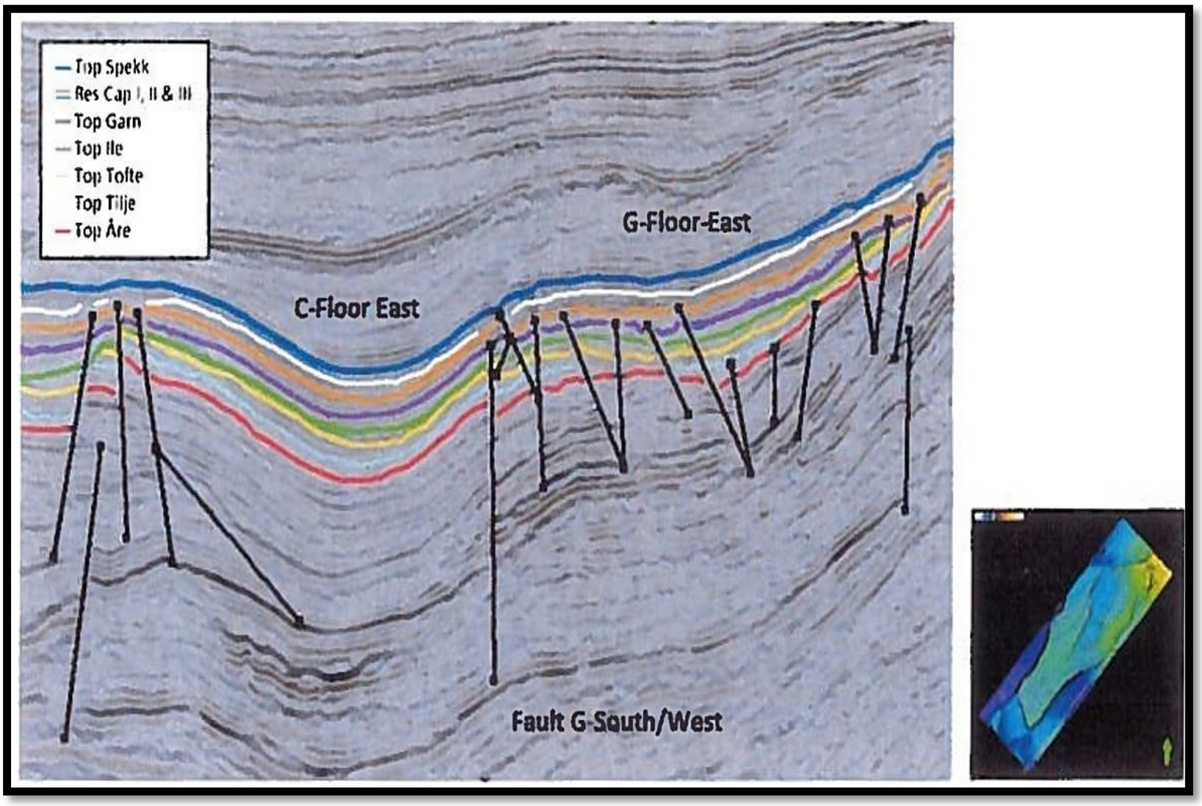


Figure 32: Bottom: From SW to NE; the C-Floor-East, the G-South/West fault and G-Floor-East. All in all, it's a nice seismic line. However, its relevance to the reservoir itself is limited. Top: Surface map displaying the outer boarders of the field.

6.1.9 Seismic Line 5: Section B

Section B has numerous interesting structures & features. In contrast to intersection 10-2/10-3, Section B cuts through the C block and then NE through the G block (figure 33). The line also comprises of two parts. In the first southernmost part, we see the C-Floor-West flanking the C-West fault. Then the dip of Top Spekk helps us interpret the DG-Trench. Further up NE in the second part we see some

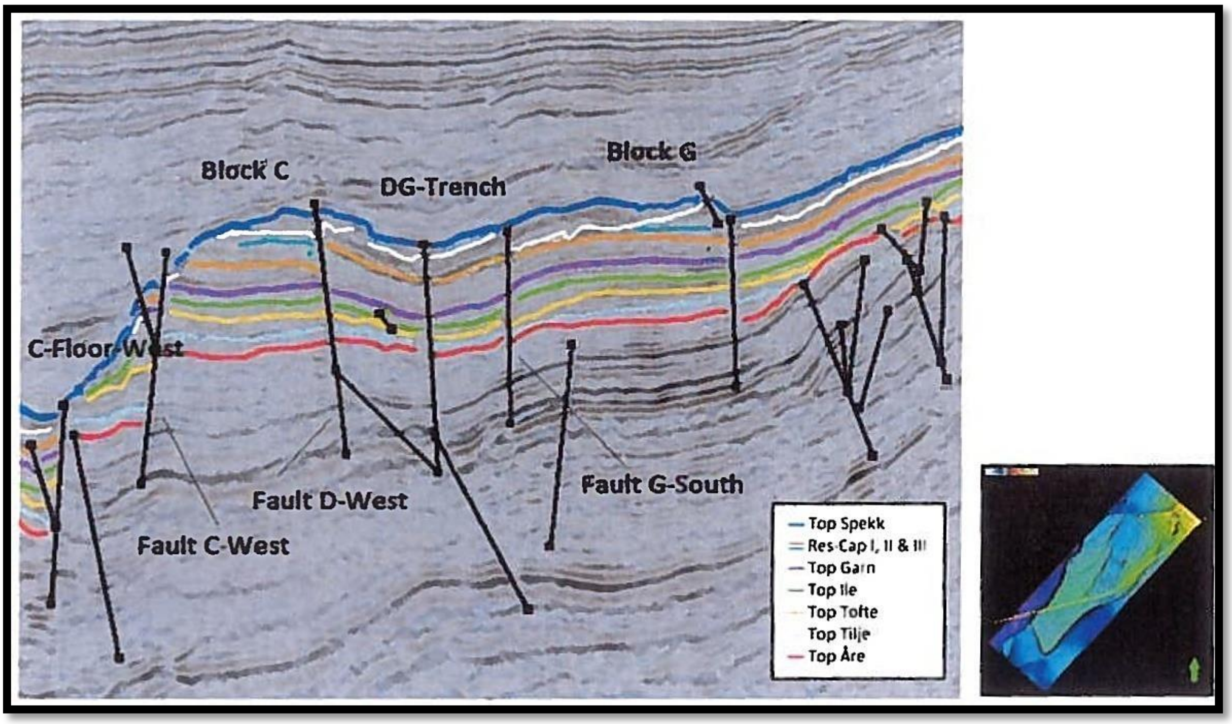


Figure 33: Bottom: From SW to NE; the C-Floor-West, the C block and some minor G block faults. Further up NE the G block is interpreted.Top: Surface map displaying how Section B cuts through the C and G block.

of the small faults in the G block. Section B ends in the northern sections of the G block, this area is characterized by its layering sequence although it from other angles may seem messy. Also there seem to be several unconformities in the NE area. This correlates well with literature; indeed the Top Tofte and Top Tilje formations are subjected to erosion, and a extensive space has been documented in the locality. Below these unconformities several faults going in both directions has been interpreted, Even though they fall outside the area of interest (deep and outside the main reservoir zones). As with intersection 10-2/10-3, Section B lets us inspect the geology from another angle, compared to the standard in- and crosslines. Typically the topography of Top Spekk lets us familiarize with the field. Except for the C-Floor-West seismic ties seems ok and reflectors are interpreted straight forward.

6.1.10 Seismic Line 13: Crossline 2100

Crossline 2100 is fairly tricky to interpret (figure 34). In the western parts we are just north of the E block, revealing its shift from the elevated block to the lower north floor. Some other faulting features may also be the cause of this disordered section. The westernmost big fault is interpreted as being E-West, although the murkiness of the image makes it hard to tell. East of E-West the straight deep faults are a bit interpreted to located below at the northern parts of the DG-Trench. Additional SE I interpret the more continuous layers to be parts of the G block. This northern part of the field ends in an uplifted area, and some faults of the G block also are interpreted. Although the murkiness of the reflectors may create awkward seismic-ties,these interpretations still are important as they help sketch the principal horizon topography. In other words, there is no point in only having nice and well-interpreted seismic lines if the overall horizon is strictly mis-interpreted due to the fact that odd lines like these are left out. Rather, they tell interesting and important structural features of the sub surface. As we see, Top Spekk and Top Are keeps somewhat together even though the rest is wildly spontaneous. This section has to be re-visited in 3D.

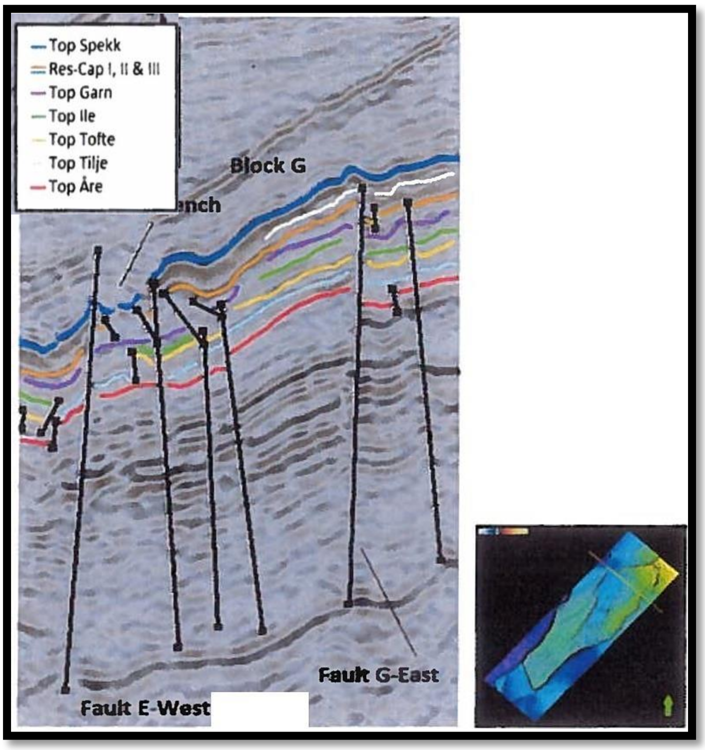


Figure 34: Left: From NW to SE; reflector chaos kept in place by larger faults and Top Spekk and Top Åre. Although this line is tricky, it reflects some of the challenges in the interpretation that has to be dealt with. Right: Surface map displaying how crossline 2100 cuts through the northern parts of the E block, the DG-Trench and the G-block.

6.1.11 Seismic Line 3: Intersection 10-3/10-4

Corresponding to Intersection 10-2/10-3 and Intersection 10-2/10-4, Intersection 10-3/10-4 completes the triangle (figure 35). From west to east we first have some big faults all interpreted as D-West 1, 2, 3 and 4. For reasons already discussed, in 2D these features may in fact signify parts of a larger fault plane or represent sub-faults in a more composite system. The D block is distinct though, and the reflectors seem to be properly interpreted. However, indications of mis-tie in the centre of the D block, but this may be due to the interpretation of i.e. crossline 2100 (having some issues). As mentioned, this part has to be taken extra care of in the 3D interpretation anyway, so we accept this mis-tie for now. Further east I interpret the D-internal and D-east faults. Once again Top Spekk topography dip reveals the DG-Trench and the G-West fault can be interpreted on its eastern side. Moving into the G block at a 45 angle to its NE trend, I interpret some small faults; still they may very well define important reservoir zones. As we see, the evident related minor fault blocks are not insignificant although their presence is in few words discussed here. All in all, the reflectors across Intersection 10-3/10-4 are not too difficult to interpret to that the formations within these major blocks seem rather layered and organized, though the major faults divide them and make up corresponding fault blocks.

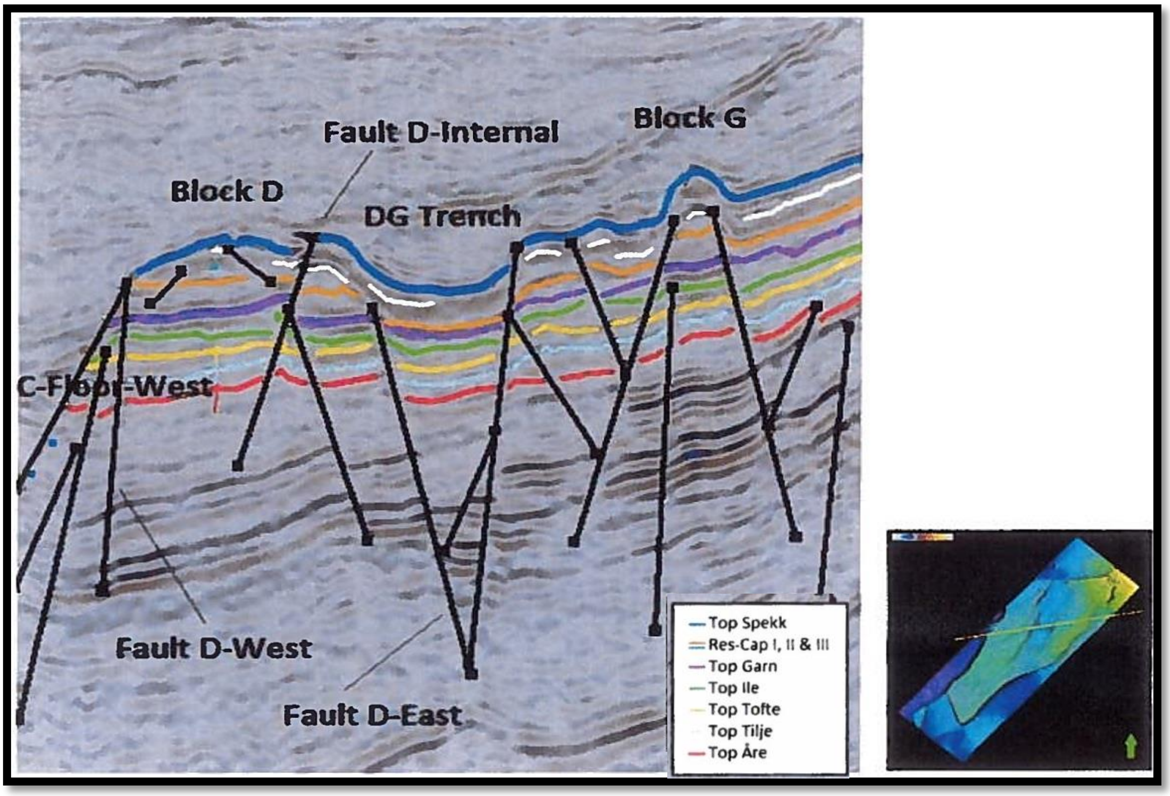


Figure 35 Left: From west to east; the northern parts of the C-Floor-West ends in multiple faults interpreted as D- West 1, 2,3 and 4. Further east the D block is more organized characterized by the D·Internal and the D·East faults. Then further east follow the DG-Trench before we move Into a faulted zone of the G block. The latter block ends in the upward reflector trend. Right: Surface map displaying how Intersection 10-3/10-4 makes up the last side in the intersection triangle.

6.1.12 Seismic Line 14: Crossline 2300

Crossline 2300 defines the NE-most part of the Norne Field (figure 36). Even while muddled in terms of faulting and reflectors, this seismic line make up an important border in terms of perspective interpretation. Therefore Top Spekk, Top Garn and Top Are identify limits and Top lie, Top Tofte and Top Tilje is interpreted a bit in between these. However, the later formations are known to be eroded in this area and some of the discontinuities in these reflectors may reflect this. Nonetheless, Top Tofte and Top Tilje reflectors are understood to be partly present although their thicknesses may vary. This also typically will subject for further interpretation in 3D. From NW to SE, the northern part of the E block dips into what is interpreted as the E-Floor-North. This in turn borders what is interpreted as the N-West 1and 2 faults followed by the N block. East of the N block, we once again see the G-West fault followed by the G block.

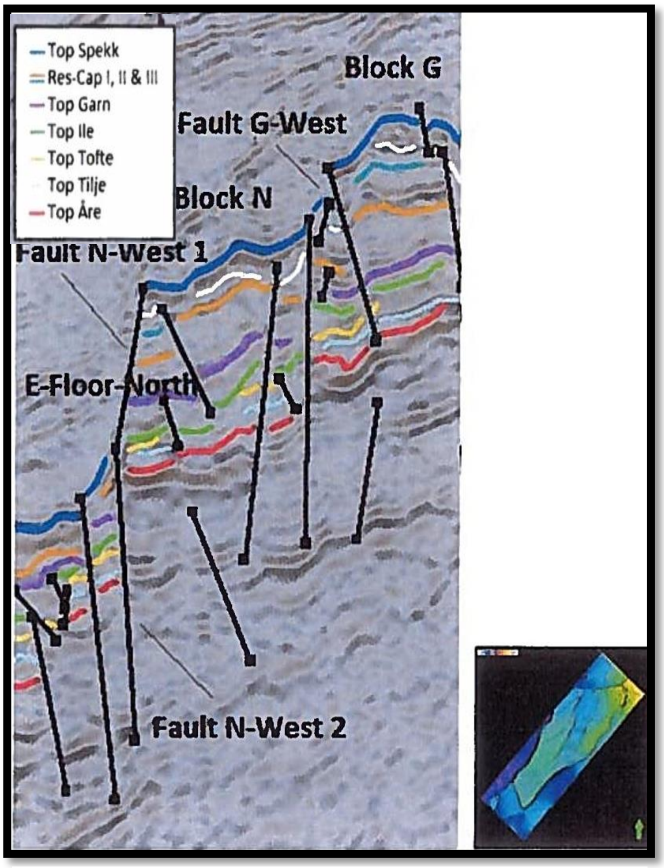


Figure 36: Left: From NW to SE; the E-Floor-North, the N-West 1 and 2 faults, the N block, the G-West fault and the G block.Right: Surface map displaying crossline 2300 as the NE-most line.

6.1.13 Seismic Line 9: Crossline 1300

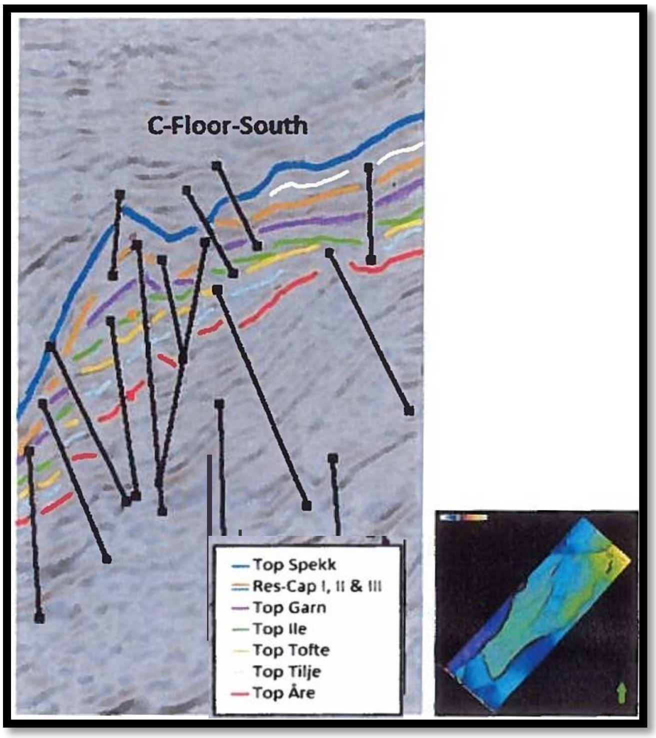


Figure 37 Left: From NW to SE, the southern parts of the C-Floor-West enter a heavily faulted zone. SE of this zone, the reflectors somewhat gets more visible again. Right: Surface map displaying crossline 1300 as the SW - most border of the field.

In the SW-most part of the field, we have crossline 1300 (figure 37). As with crossline 2300, this line makes up the field margins as well as the seismic-ties should be well thought-out. In addition wrongly interpreted reflectors will introduce mis-ties for the 3D horizon interpretation, in addition to the seismic line losing value in itself. Following Top Spekk and the successive reflectors below, one idea can be to make some reasonable margins for the prospect horizons. From NW to SE we see some medium-sized faults that sketch what seems to be the beginning of the C block (in a south to north direction). This faulting further intensifies as we look at the central parts of crossline 1300. Knowing that the C-South fault almost is at right angle to the C- West and C-East faults respectively. This may be explained by a perpendicular two -way stress field; if the major faulting aligns in one principle direction, the perpendicular faulting in the stress field will commence several in between-directed faults. Simply put, stresses going in all directions making up a composite fault system. However, this is at a lower physical scale than that of the major faults outlining the main structures

6.1.14 Seismic Line 6: lnline 1070

Inline 1070 symbols the end of the 2D interpretations and act as a vital correlating line in terms of seismic ties (fig 38). By now, most of the reflectors should have suitable ties in this line as it cuts the whole field in half from SW to NE. From SW the C-Floor-South is definite; not too difficult to interpret and the C-South fault simply seen as it separates the floor from the C block. The reflectors continue into the C block, encountering some minor faults, before reaching what is interpreted to be the D-internal fault. The line further dips into the DG-Trench outlined by Top Spekk. Then, all the way up NE I interpret the N-West fault. Some of these faults act as guidelines for further and more comprehensive studies in the 3D interpretation, so even though these faults not always are accurately correct (they may be located somewhat further away in whatever direction compared to the absolute major fault). They still outline the main structures. In general, inline 1070 have good seismic ties and serves as a solid anchor for the 3D horizon interpretation; horizons can be developed from either side of the line. Once again, inline 1070 shows some of the principal geological structures in the field with clear and visual reflectors.

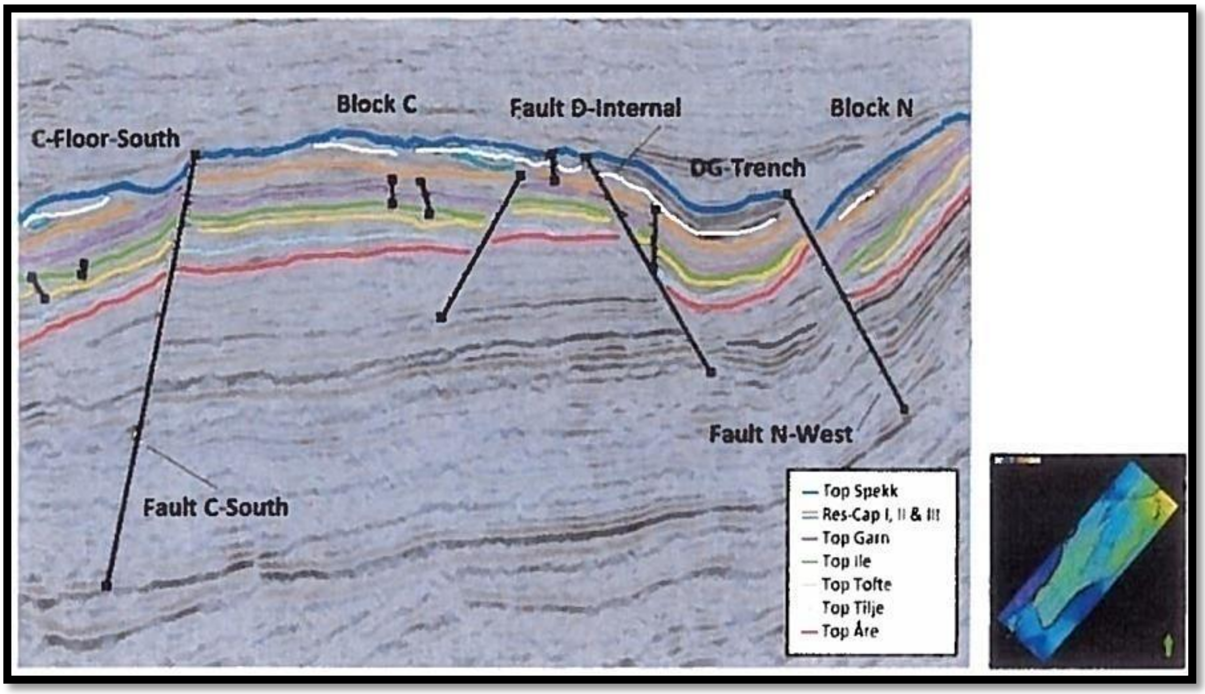


Figure 38: From SW to NE; the C-Floor-South, the C-South fault, the C-block (seen along the block), the D-lnternal fault, the DG·Trench and N-West fault. In general, most of the reflectors appear to be strong and well layered. The reflectors are therefore relatively easy to interpret compared to some of the more difficult crosslines. Right: Surface map displaying the anchoring properties of in li ne 1070.

6.2 Surfaces

6.2.1 Top Garn:

The Top Garn horizon was fully interpreted by running through in- and crosslines at 20 lines spacing. It was interpreted in 30 using seeded, guided and manually interpretation (figure 39).

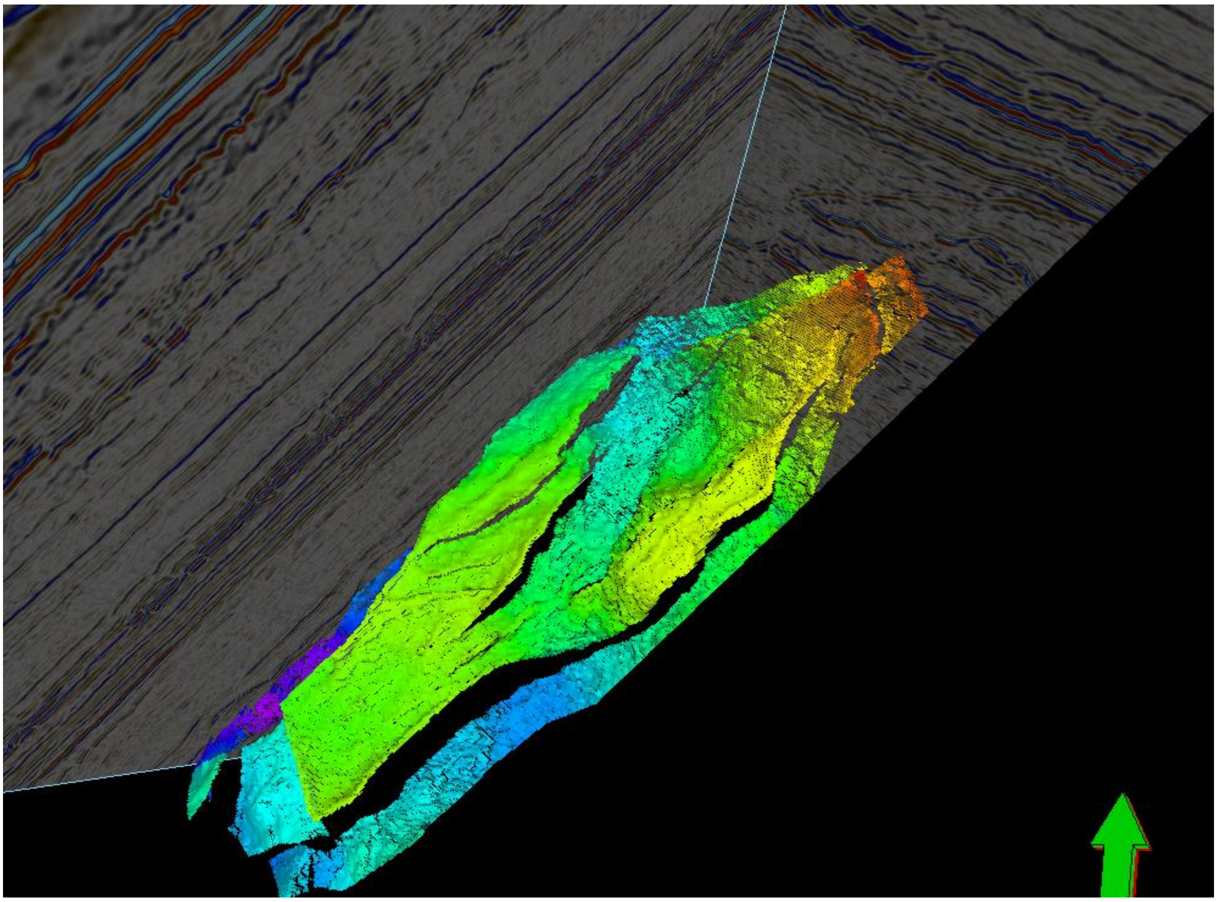


Figure 39: 3D overview of the Top Garn horizon.

Although 3D horizon interpretation sometimes can be tricky (fully interpreted sections may belong to other formations), I start by investigating seismic ties such as the junction between crossline 1700 and inline 1270. This way I outline some of the principal structures in the subsurface.

I start creating the automatically 3D interpreted horizon. This can automatically be completed in Petrel and quality of the calculation clearly depends on the number of interpreted lines; the more interpreted lines, the more likely the result will be reasonable.

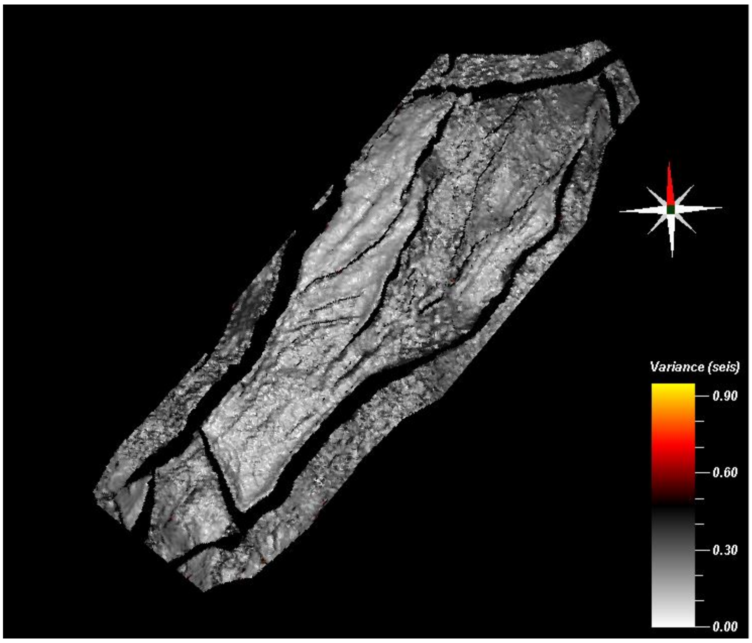


Fig 40 : The Top Garn Variance showing faults

By means of the 3D interpreted Top Garn horizon, I created a surface. The first surface may exhibit sharp edges and missing areas in the interpretation due to mis-ties etc. These are more effortlessly seen on the surface than on the horizon, and the way to fix this is to go back to the latter and to manually correct them.

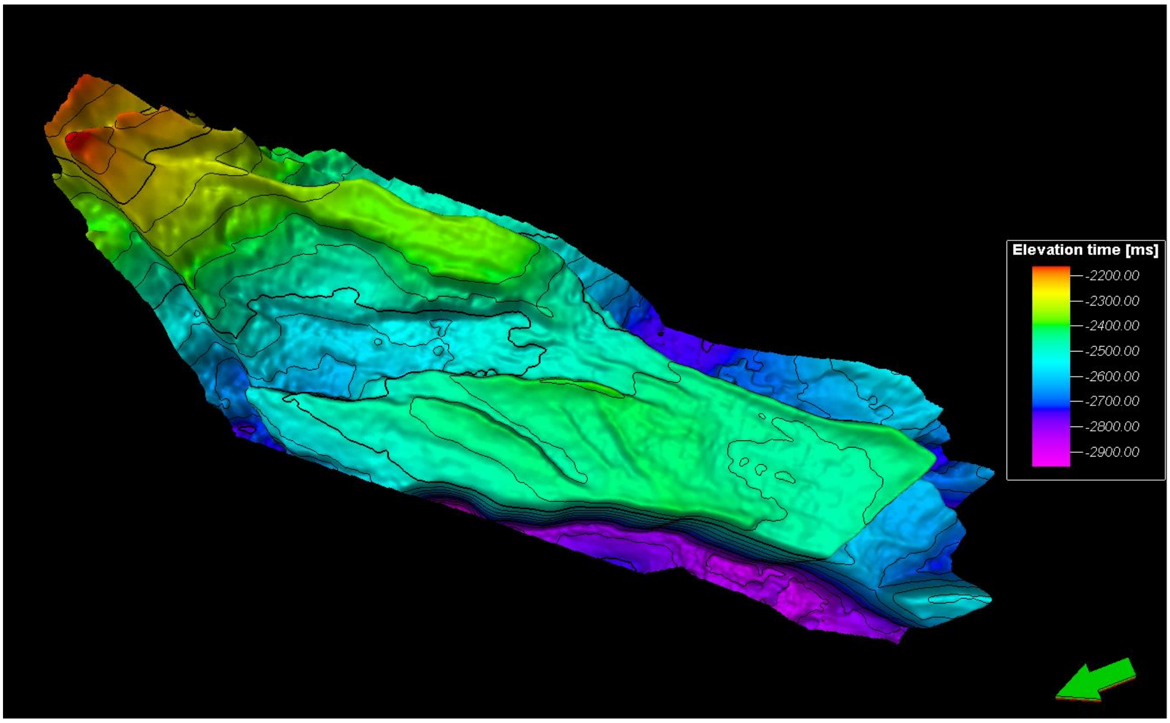


Figure 41: Top Garn surface. Smoothing was done using filter width 1 and 1 iteration. This is defined to be top reservoir and faults and corresponding faults block will be discussed in more detail in conclusion section of this master's thesis

6.2.2 Top Åre

The Top Åre horizon was wholly interpreted by running through in- and crosslines at 10 lines spacing (figure 42). Thought to be the Norne source rock, Top Åre is a vital horizon although it also can be quite hard to interpret. Correlated in wells 6608/10-2 and 6608/10-4 and interpreted as a support for the zone of interest in the 2D interpretation, its being across the field is well-known.

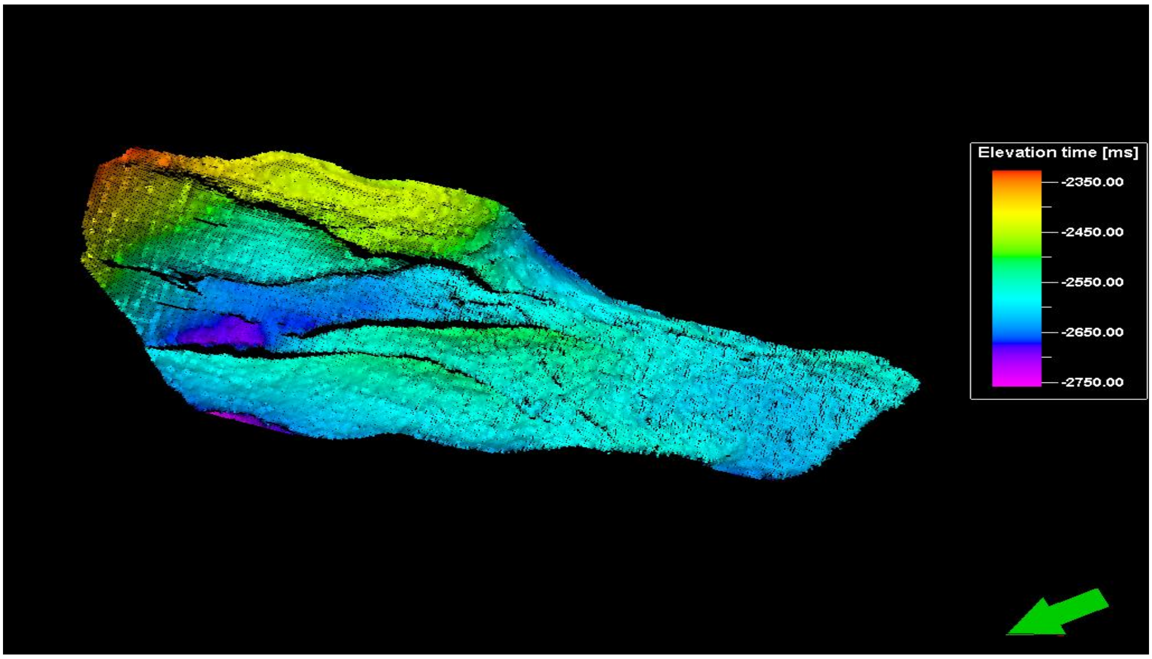


Figure 42: Top Åre after the 3D auto tracking. Missing areas has are fixed.

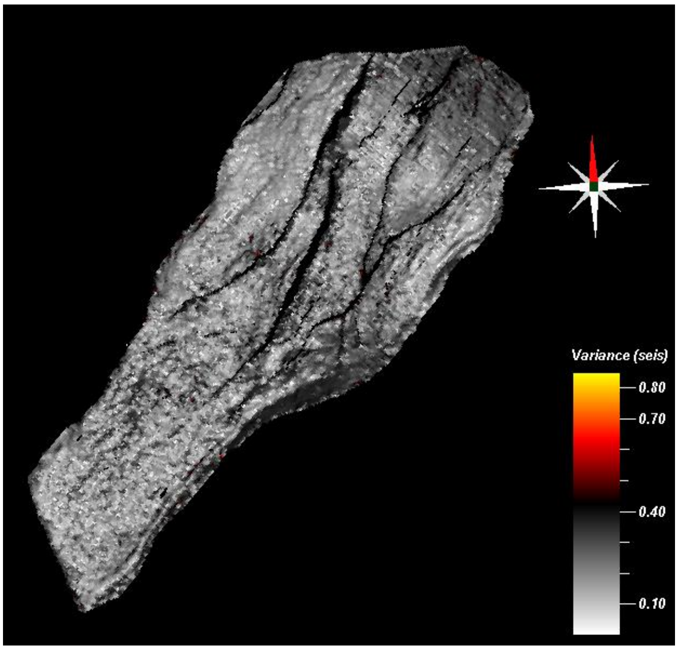


Figure 43: Top Åre variance

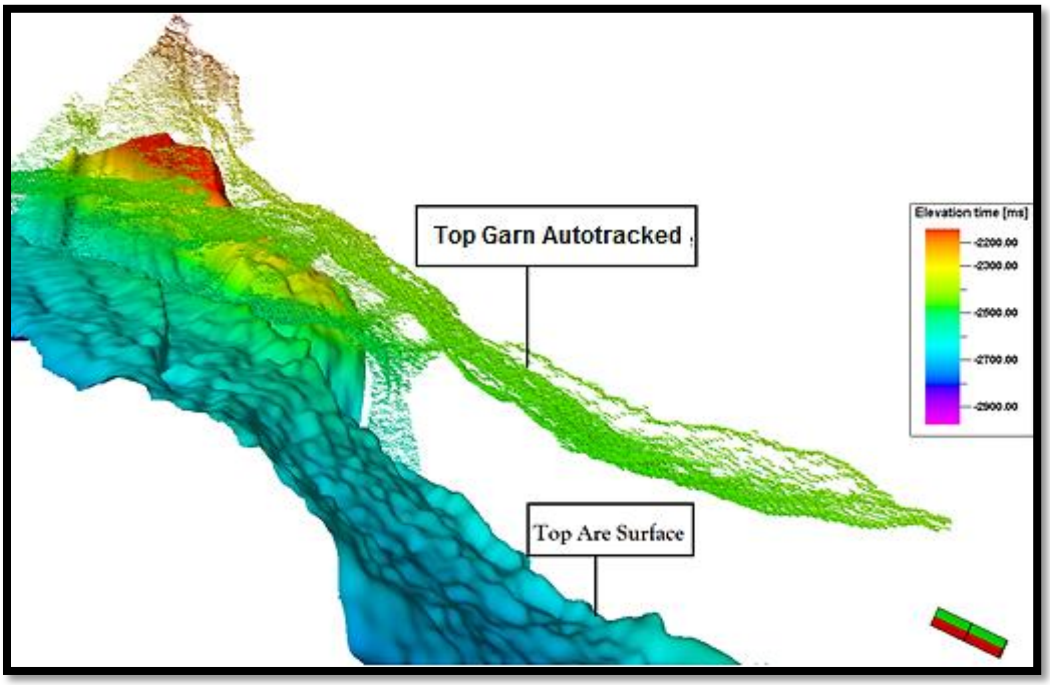


Figure 44 : Top Not and Top Are, defining the reservoir and the area of interest in this thesis. As we can see, further QC of the interpretation has to be done.

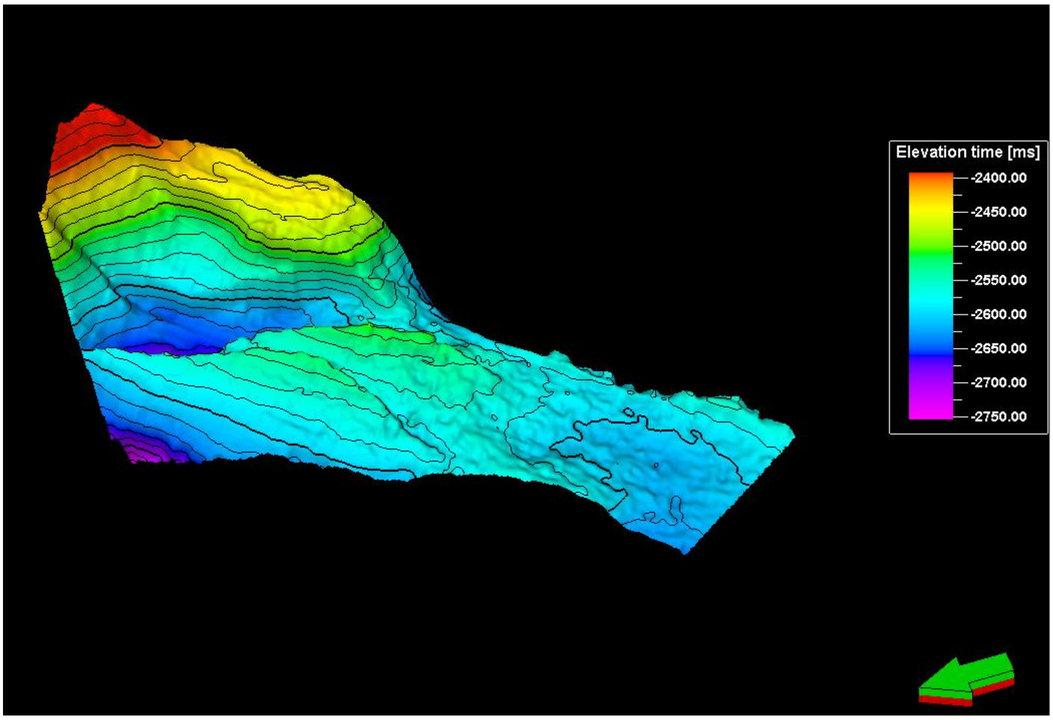


Figure 45: Top Are surface. Smoothing was done using filter width 1 over 1 iterations. In this image we see how the southern parts even out In front of the principal SE block. However the two major faults on either side of the block still are clearly visible, revealing the outline of this elevated block.

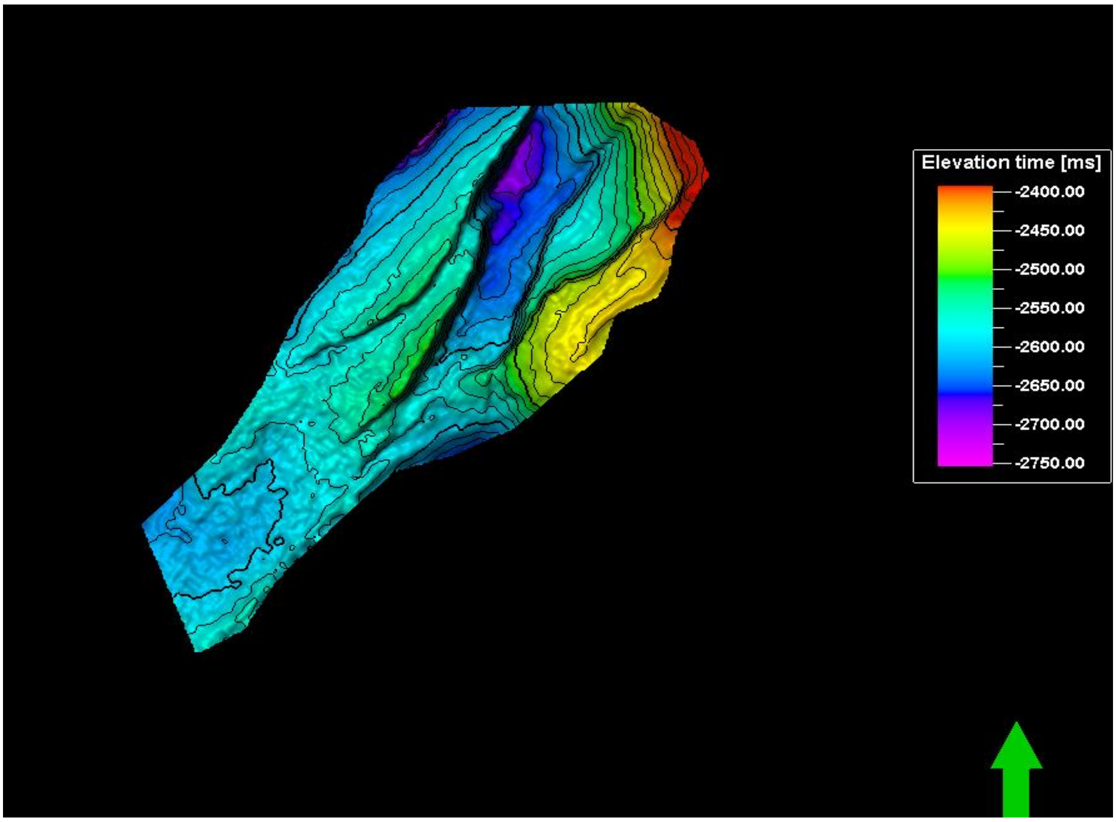


Figure 46: Top Are surface. Smoothing was done using filter width 1 over 1 iterations. Even though the central parts of the field also is somewhat smoothed out, the base of the three major fault blocks can be seen.

7 Petrophysical Interpretation

The petrophysical studies of the Norne main field is based on data from two exploration wells 6608/10-2 & 6608/10-4. In 1994 the exploration well 6608/10-4 was drilled in the G-segment creating base for the petrophysical study of this area. The base measurements for the evaluation is wireline log.

A total picture of the porosity of the Norne Field is obtained by density porosity and neutron posrosity. The water saturation has to be calculated using Archie's formula. For the G-segment, separate values for porosity, water saturation and permeability were calculated. The Norne reservoir has good to excellent reservoir properties with mean porosities in the range 20% - 30%, average net to gross value in the range of 0.7 – 1.0, water saturation from approx 12% to 43% in the hydrocarbon zones and permeability values ranging from approximately 20 to 2500 mD.

7.1 Well Information: Well 6608/10-2.

Spudded at: 28th October 1991

Total depth (TD) of the well was at 3678 m below Rotary Kelly Bushing (RKB), and this depth was reached December 16th the same year. In January 1992, four drill stem tests were carried out on this well, which tested gas in the Garn Formation, oil in the Tofte Formation and water in the Tofte/Tilje Formation. The well discovered a hydrocarbon column of 135 m in the rocks of Lower and Middle Jurassic. 110 m was oil, and the rest was an overlying gas cap.

Table 1: Detail description of well 6609/10-2 (NPD, 2010)

NPDID wellbore:	1782
Well name:	6608/10-2
Drilling operator name:	Den norske stats oljeselskap a.s
Geodetic datum:	ED50
Coordinates:	66° 0\` 49.35\`\` N - 8° 4\` 26.48\`\` E
UTM coordinates:	7321933.62 N - 457994.68 E
UTM zone:	32
Drilled in production licence:	128
Area:	NORWEGIAN SEA
Discovery:	6608/10-2 NORNE
Field:	NORNE
Drill permit:	701-L
Drilling facility:	ROSS RIG
Drilling days:	94
Wellbore entry date:	28.10.1991
Wellbore completion date:	29.01.1992
Original wellbore purpose:	WILDCAT
Wellbore purpose:	WILDCAT
Wellbore status:	P&A
Wellbore contents:	OIL/GAS
Discovery wellbore:	YES
Formation/age with hydrocarbons 1:	NOT / MIDDLE JURASSIC
Formation/age with hydrocarbons 2:	Ile,Tofte / EARLY JURASSIC
Seismic location:	NRGS 85 -NRGS84 - 451& SP. 780
Kelly bushing elevation (KB) [m]:	23
Water depth [m]:	374
Total Depth (MD) [m]:	3678
Final vertical depth (TVD) [m]:	3677
Max inclination [°]:	4.00
Bottom hole temperature [°C]:	133
Oldest penetrated age:	LATE TRIASSIC
Oldest penetrated formation	ÅRE FM

7.1.1 Garn formation well 6608-10/2:

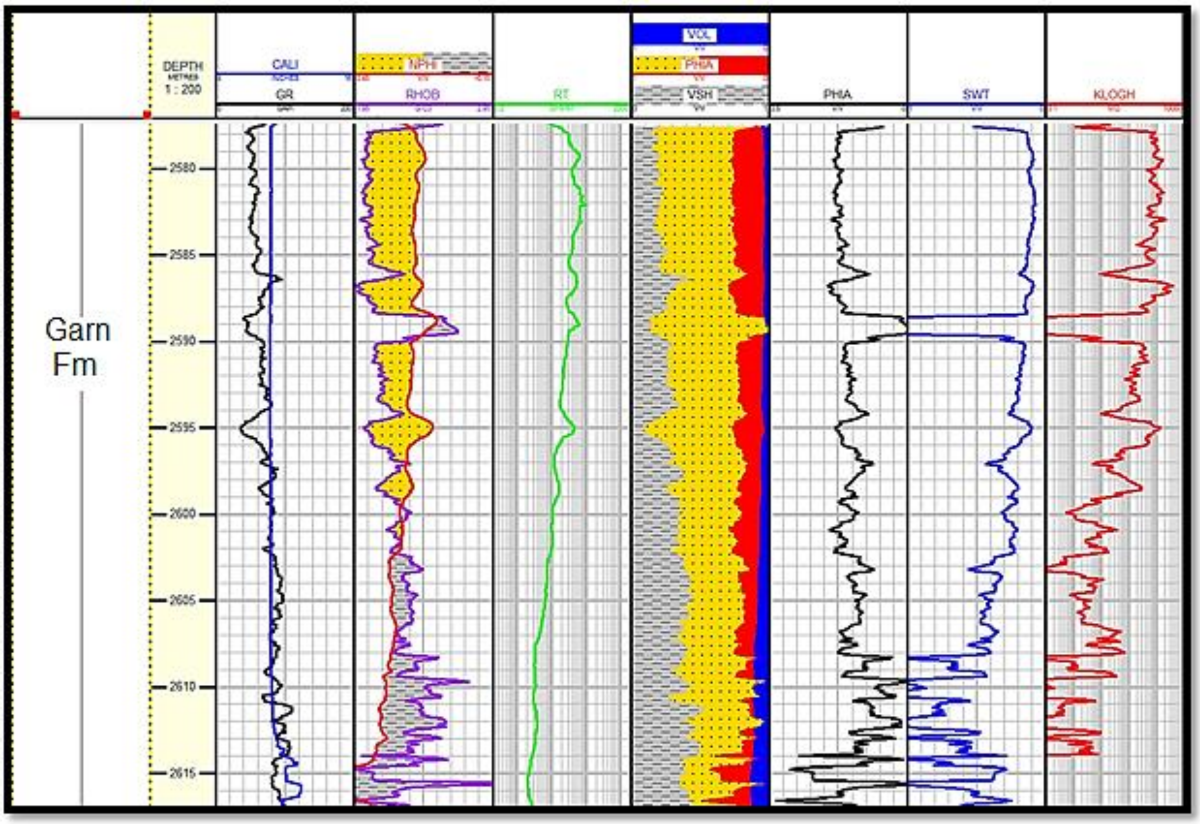


***Fig 47:** CPI (computer processed interpretation) of Garn formation*

Garn formation was deposited during the Late Aalenian and the Early Bajocian, and is 35 m thick sandstone. The depositional environment was near shore with some tidal influence. Reservoir quality is increasing upward within the formation, from pretty good in the lower parts to very good in the upper parts. This formation is also divided into reservoir zones based on differing properties and deposits. For the Garn Formation the number of reservoir zones is three. Garn 1 is a sandstone unit which is coarsening upward, from very fine to fine grained sand. The lower part is muddy and bioturbated, as it is the continuance of the ot Formation, while the upper part has an increased sand content. This part of the formation has faster beddings, ripple lamination and thin layers of coarser grained sandstone. [Statoil, 1994a]

The Garn Formation is much thinner in well 6608/10-1 and most of Garn 2 and the entire Garn 3 are missing in this well. This is due to tectonic uplift in the north during the deposition. The Garn Formation south of the Norne field is thicker due to higher subsidence rates, which give more accommodation space. At the top of Garn 3, sandstone and mudstone sediments with floating clasts are found. This is a result of ravinement and reworking during a transgressive period. [Statoil, 1994a]

In well 6608-10/2 ,Garn formation is gas filled. As from figure 47, Gamma ray log values are low that means Garn fm is sandstone in the middle (shale in upper and lower parts). Some higher GR values shows maybe carbonate stringers. NPHI (neutron porosity) and RHOB (density log) have higher separation (2578-2599), which is also an indication for gas. RT (resistivity log) shows higher resisitivity values. SW (water saturation) shows lower readings while permeability readings are high.

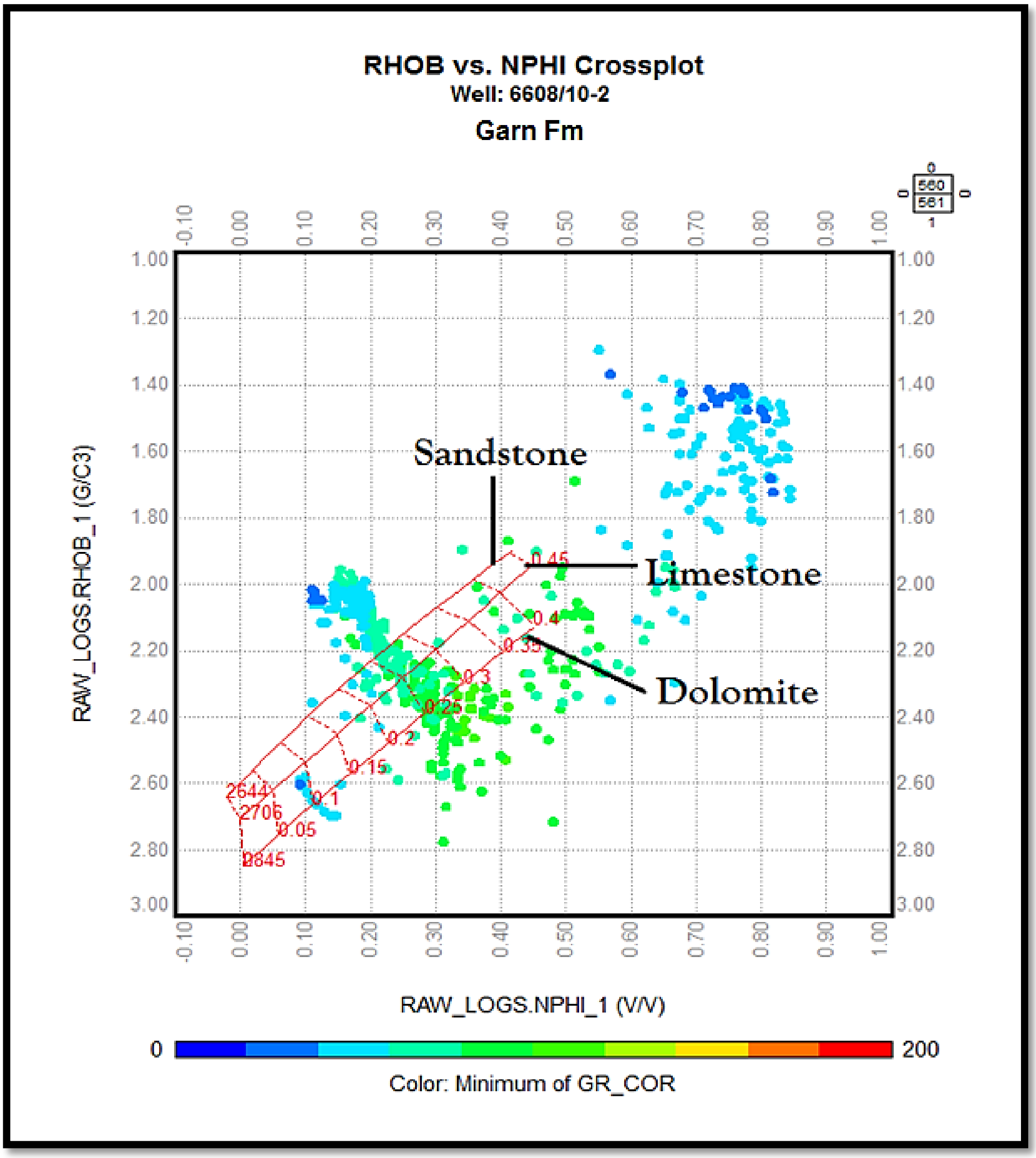


Fig 48: X-plot representing Garn Formation.

Fig 48 shows cross-plot of Garn formation between NPHI and RHOB. Three red lines in fig 48 shows lithology (sandstone, limestone, dolomite). Points above first line shows the presence of gas. Not Formstion is a Sand stone in the middle. In the neutron-density cross-plots (Fig 48), data points from the well 6608-10/2, Garn formation have been plotted. Only the points with less than 25% shale (Vsh<0.25) have been plotted. By using this cutoff (Geolog), the shale intervals are removed from this data as this plot (overlay lines) only valid for pure sandstone, limestone and dolomite. Figure 48 demonstrate that only some points do not fall outside the pure sandstone line, which may belong to calcite or data from the intervals of bad boreholes.

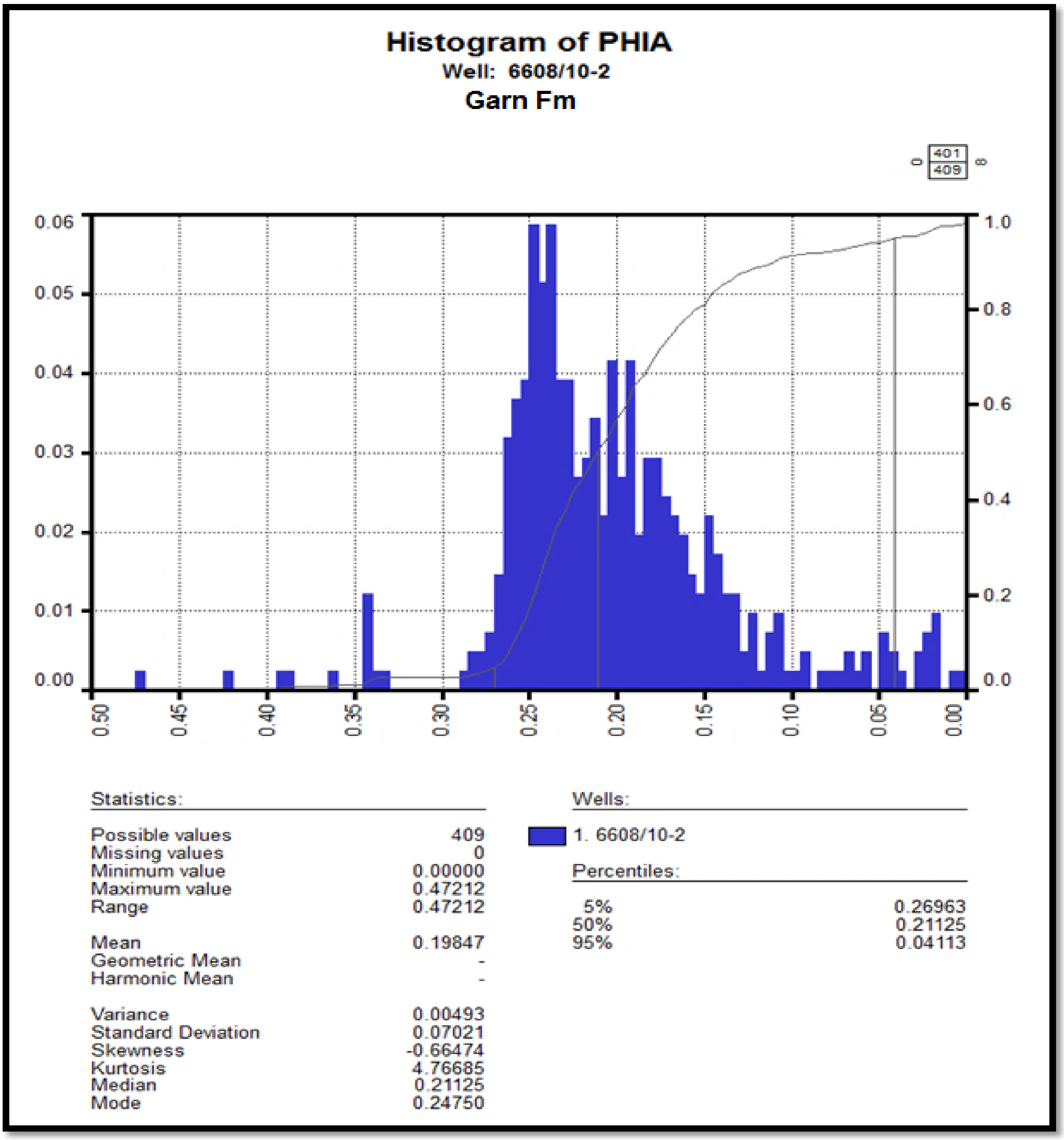


Fig 49: Histogram showing porosity of Garn formation. Average porsotiy within is 20%.

Porosity is one of the basic parameters to define the reservoir quality. The porosity logs (Neutron, Density and Sonic) may give us different values under different lithologies. The porosity of reservoir rocks have been estimated and described further by usual methods (porosity prediction from neutron and density logs), as well as sum of two or three porosity logs to estimate average porosity. The single log porosity estimation, like porosity from neutron log overestimate the value of shales (Fig 49), as they are more sensitive to the HI (hydrogen index), which may present in shale/clay lithology as bounding water (Rider and Kennedy, 2011). The density value underestimate the value in shale zone, even varied value of matrix density have been used in calculation of density porosity as mentioned earlier in the chapter 5 . The average values however provide better results (Fig 49). For better understanding of the porosity values, all data points of average porosity from the well 6608-10/2 have been plotted in a histogram (Fig 49). The mean value is 0.19 ,which show that the reservoir has decent porosity.

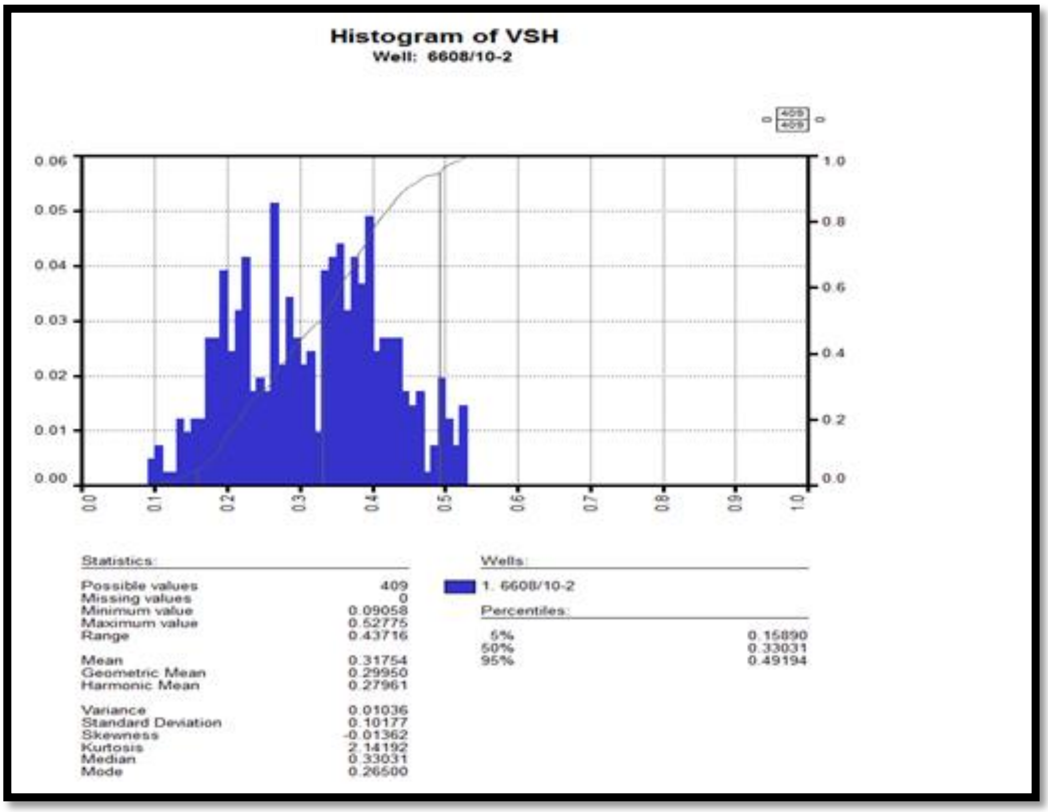


Fig 50: Histogram showing shale voulme of Garn formation. Average VSH within is 0.31.

From the petrophysical analysis and literature (Verlo and Hatland, 2008) it is clear that the reservoir sandstones of Garn formation in the Norne area contains sandstones and shales. The estimated volume of shale may helps to differentiate the sand and shale beds, which helps to evaluate the commercial reservoir intervals (Fig 50). Further, all data points of shale volume from well 6608-10/2 have been plotted in histogram. It is observed that the mean value is approximately 0.31. This simple but informative histogram shows that the reservoir intervals have clean sandstone of good quality with only minor shale content (Verlo and Hatland, 2008).

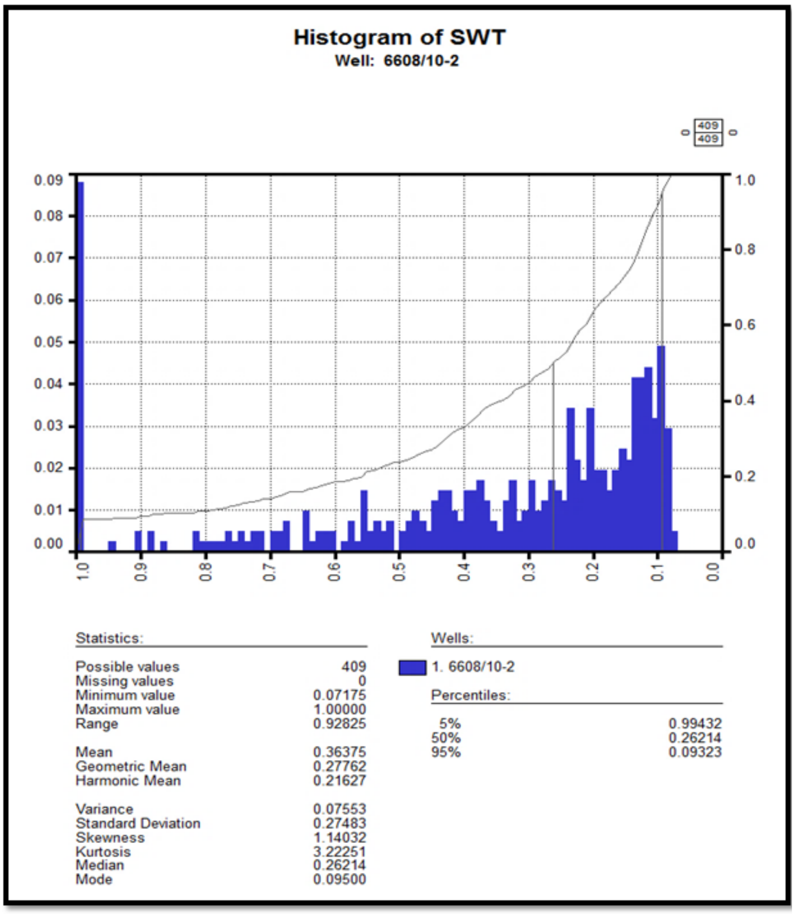


Fig 51: Histogram showing water stauration of Garn formation. Average SWT within is 0.36.

In the petrophysical evaluation to calculate hydrocarbon saturation the resistivity logs are the most used one. It isquite easy to separate the hydrocarbon saturated zone from the water saturated zone with the help of deep resistivity log (Fig 51). The water saturation has been calculated after estimating the porosity and the volume of shale in well 6608-10/2 for Garn formation. On the basis of the water saturation, the hydrocarbon saturation have been estimated. In the reservoir interval water saturation is in average 0.3, which indicates that hydrocarbon saturation in this zone almost 0.7.

Zone	Top Fm.	Bot Fm.	VSH	PHIA	SW	KLOGH
	(m MD RKB)	(m MD RKB)	(frac.)	(frac.)	(frac.)	(frac.)
Garn	2565	2615	0.31	0.19	0.36	278

Table 1 : Statistics from Petrophysical Evaluation for well 6608-10/2, Garn formation

7.1.2 Ile Formation 6608-10/2

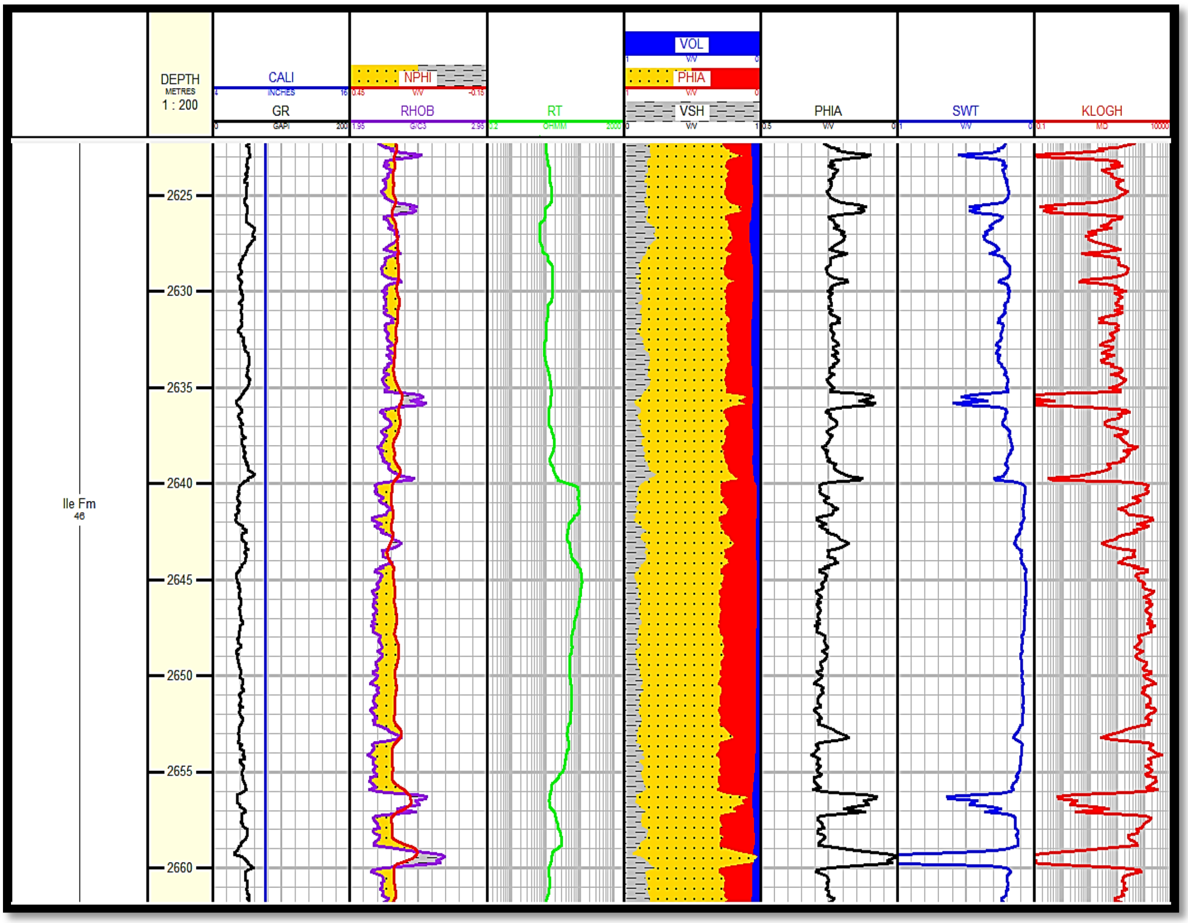


Fig 52: CPI (computer processed interpretation) of Ile formation

The Ile Formation was deposited during the Aalenian, and is about 32-40 m thick sandstone. The depositional environment of Ile formation was in the shoreface. This formation is further divided into 3 reservoir zones; Ile 1, Ile 2 and Ile 3. The separation between Ile 1 & Ile 2 is a cemented calcareous layer. These layers were probably the result of minor flooding events in a regressive period. Both the calcareous layers are assumed to be continuous throughout the Norne Field. Ile 2 and Ile 3 are separated by a sequence boundary, which higlights, the change from regressive to transgressive environment. The reservoir quality of the Ile Formation is generally fair to good, especially in the regressive depositions, whereas the reservoir properties are decreasing towards the top of the formation. Ile 1 & Ile 2 both consist of fine to very fine grained sand which is coarsening towards north. Bioturbation, glauconites & plenty of calcareous shell fragments are all evidence of the depositional environment. Despite bioturbation some lamination and ripples can be seen, but the quantity is not enough to determine the transport direction. The coarser grained sequence boundary that was mentioned above is at the top of Ile 1. Ile 3 lies above the sequence boundary and is an largely bioturbated, upward fining sandstone of fine to very fine grains. [Statoil, 1994a]

In well 6608-10/2 ,Ile formation is oil filled. As from figure 52 , Gamma ray log values are low that means Ile fm is sandstone. NPHI (neutron porosity) and RHOB (density log) doesn't have larger separation (2625-2660), which is also an indication for oil. RT (resistivity log) shows higher resisitivity values but lower than those in Garn formation. SW (water saturation) shows lower readings while permeability readings are high.

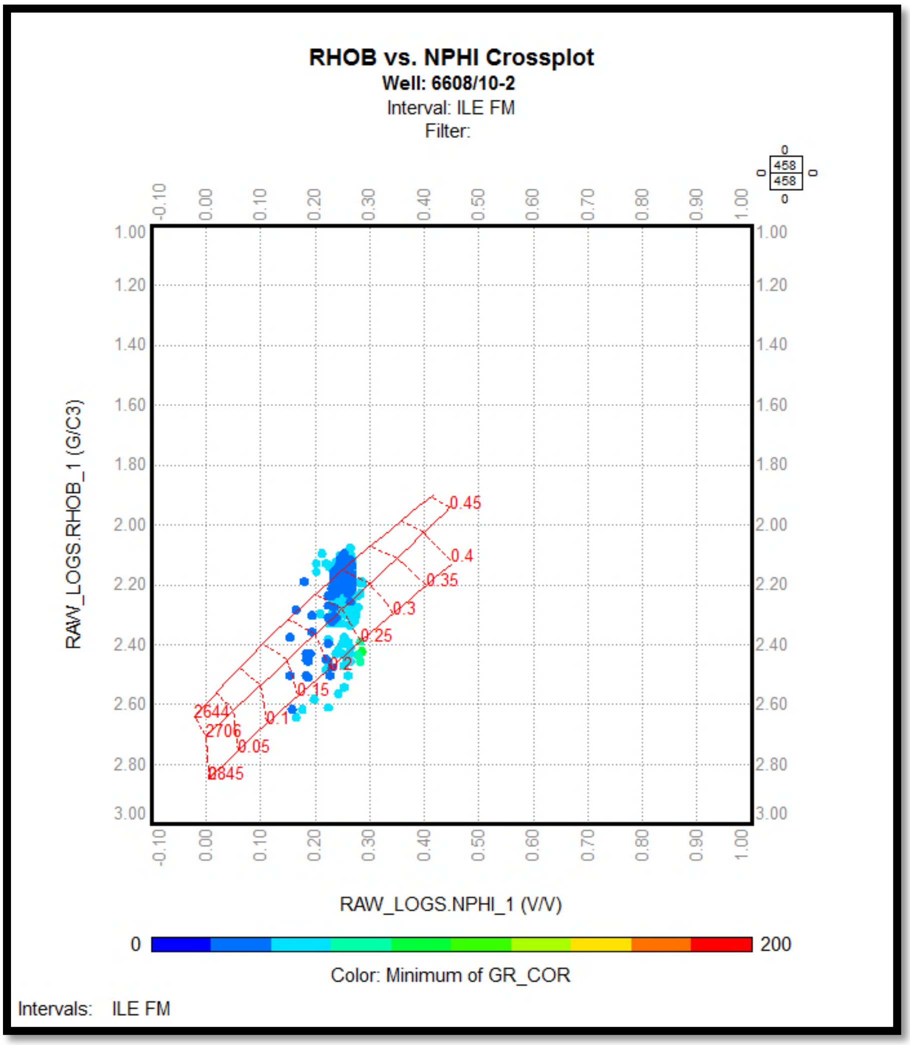


Fig 53: X-plot representing Ile Formation.

Fig 53 shows cross-plot of Ile formation between NPHI and RHOB. Three red lines in fig 53 shows lithology (sandstone, limestone, dolomite). Cluster of points below first red line from top (sand stone line) shows presense of Oil.

Gamma ray in Ile is quite stable as there isn't any variation in the reading which indicates that the lithology is quite homogenous. The reading depicts that it is clean formation as GR reads on average between (31-80) API, this is further supported by volume of shale (fig 56) ranging between (0.15 %). Sand separation (low density and low NPHI) can be observed on RHOB and NPHI log along with high resistivity values on deep resistivity (RT) which further suggests that we have good sands which are oil filled as no gas separation (large separation between RHOB and NPHI) is observed. This interpretation is further supported by density-neutron cross plot (fig 53), where most of the data plots between sand and limestone line with good porosity. As observed some of the clusters plots above the sandstone line which may be associated to some light hydrocarbon filled sands. The data which plots below dolomite line may be associated to sands with high amount of shale.

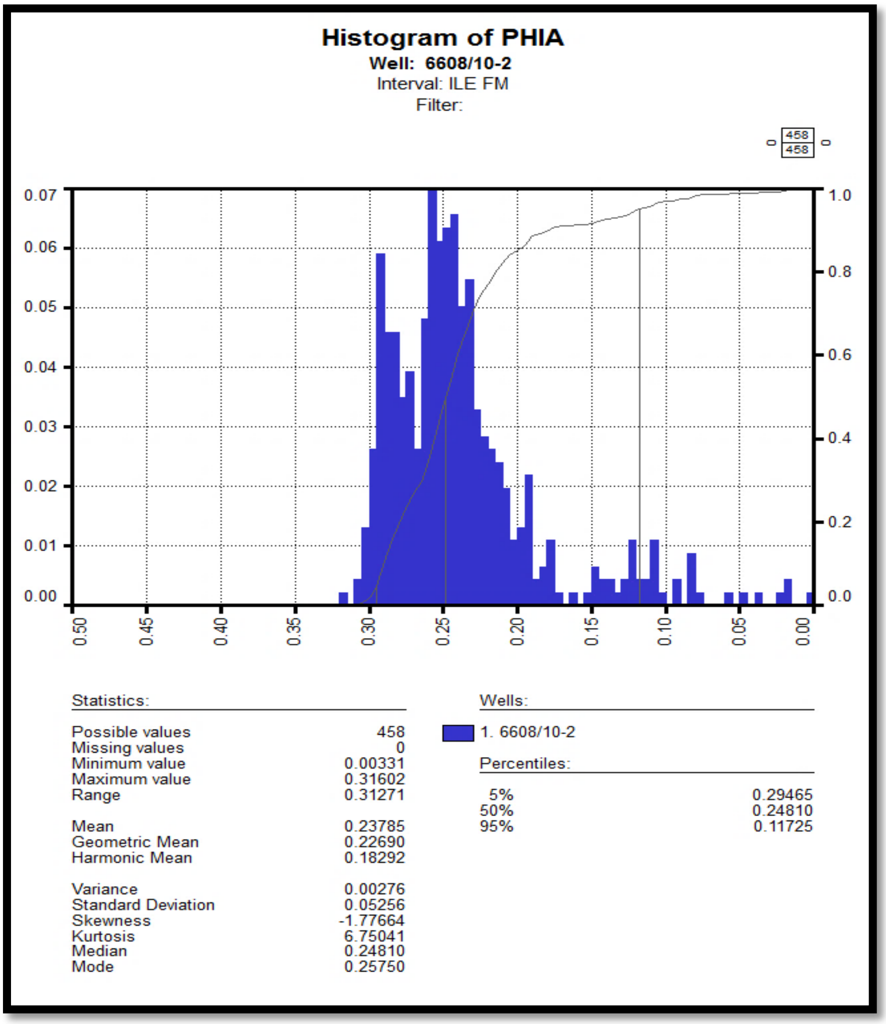


Fig 54: Histogram showing porosity of Ile formation. Average porsotiy within is 24%.

Ile formation is a good reservoir as log based porosity and permeability varies between (24% ,237 md respectively) as in figure 54 & 55. Water saturation increases as we go down into the formation.As we can see in Figure 58, Ile formation has prosoity of 24%.

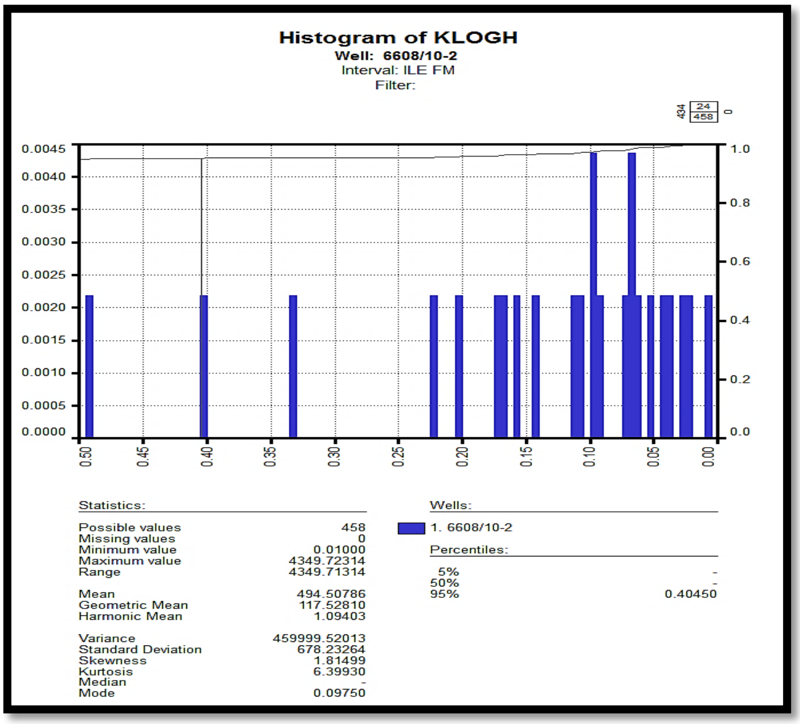


Fig 55: Histogram showing permeability of Ile formation. Average permeability within is 494md.

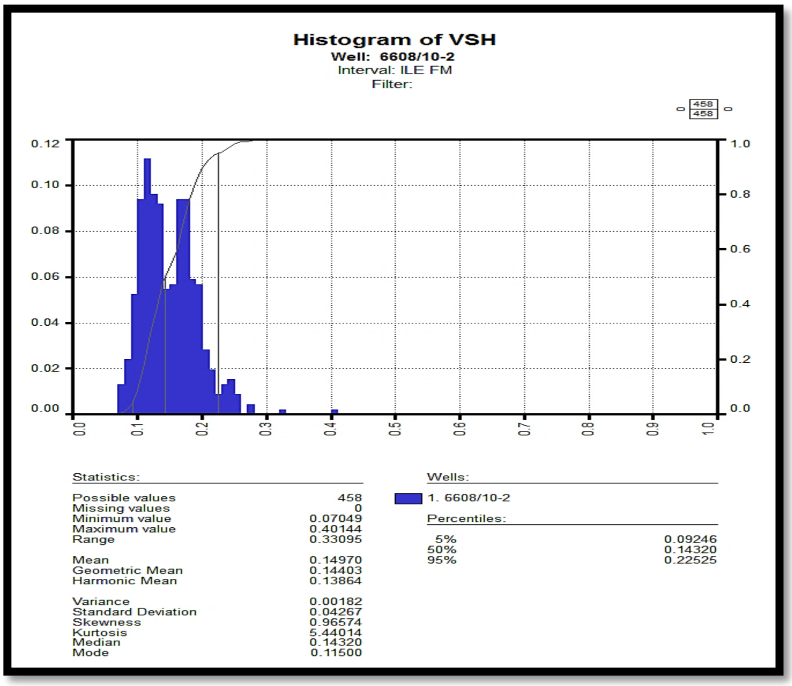


Fig 56: Histogram showing shale voulme of Ile formation. Average VSH within is 0.15.

Zone	Top Fm.	Bot Fm.	VSH	PHIA	SW	KLOGH
	(m MD RKB)	(m MD RKB)	(frac.)	(frac.)	(frac.)	(frac.)
ILE	2615	2660	0.15	0.24	0.20	494

Table 2 : Statistics from Petrophysical Evaluation for well 6608-10/2, Ile Formation

7.1.3 Tofte formation well 6608-10/2

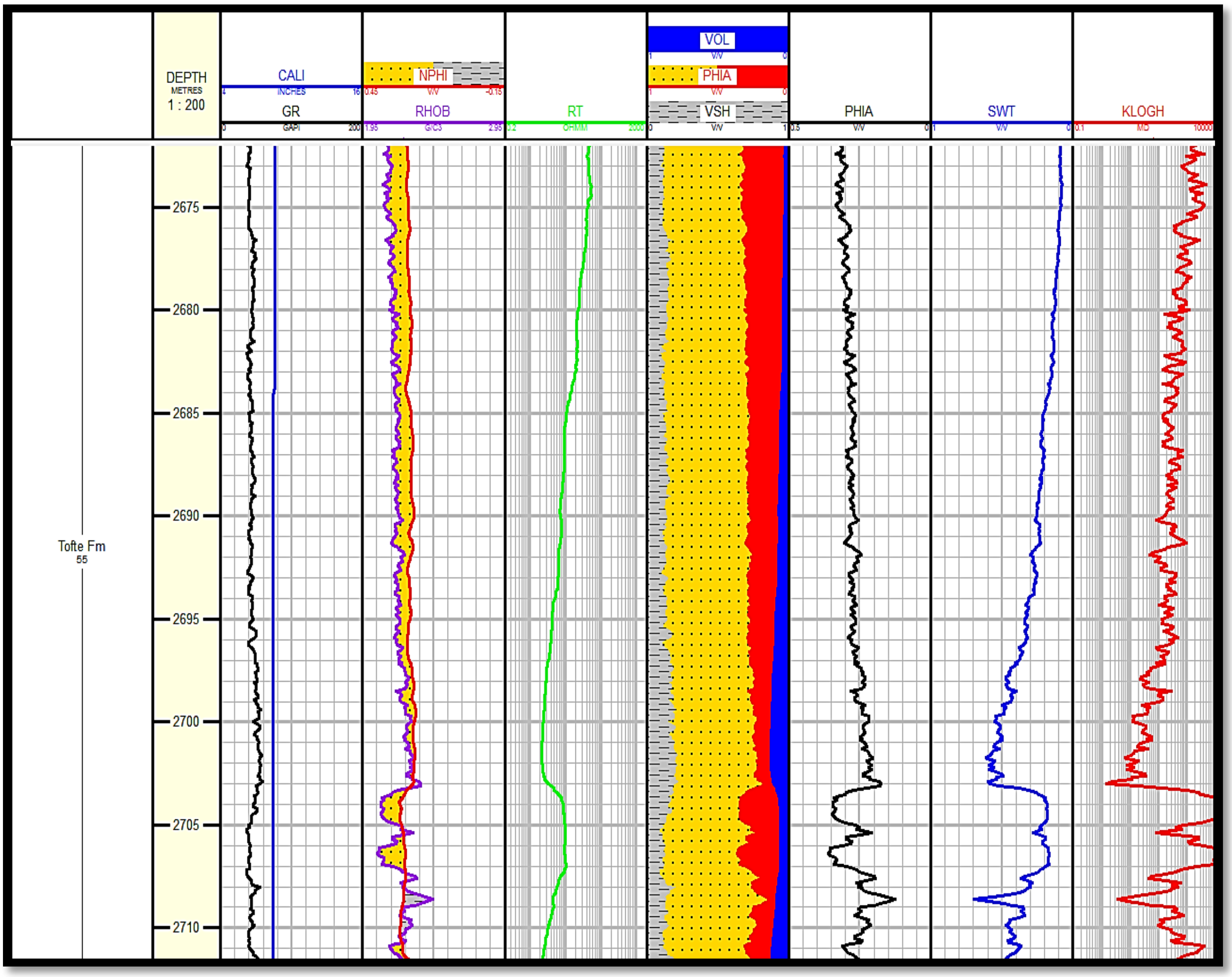


Fig 57: CPI (computer processed interpretation) of Tofte formation

The Tofte Formation is further divided into three reservoir zones. Tofte 1 is consist of medium to coarse grained sandstones. The lower parts are more bioturbated & have finer grains. The dipping of the layers suggests that the source area for sediments was to the north or northeast of the field. Another issue related to Tofte 1 formation is the limited distribution in the east-west or northeast-southwest direction. Tofte 2 is an extensively bioturbated, muddy and fine grained sandstone division. Floating clasts can be found in the lowermost part of the unit, which is coarsening upward. Tofte 3 consists of very fine to fine grained sandstone where almost not a single depositional structures are visible because of bioturbation. (Verlo and Hatland, 2008)

Tofte formation is oil filled. As from figure 57, Gamma ray log values are low that means Tofte fm is sandstone. NPHI (neutron porosity) and RHOB (density log) haven’t has larger separation (2670-2705), which is also an indication for oil. RT (resistivity log) shows higher resisitivity values. SW (water saturation) shows lower readings while permeability readings are high.

Sand separation (low density and low NPHI) can be observed on RHOB and NPHI log along with high resistivity values on deep resistivity (RT) which further suggests that we have good sands which are oil filled as no gas separation (large separation between RHOB and NPHI) is observed. This interpretation is further supported by density-neutron cross plot (fig 58), where most of the data plots between sand and limestone line with good porosity. As observed some of the clusters plots above the sandstone line which may be associated to some light hydrocarbon filled sands. The data which plots below dolomite line may be associated to sands with high amount of shale.

Tofte formation is an excellent reservoir as log based porosity and permeability varies between (27%,1087 md respectively) as figure 59 and 60. Water saturation increases as we go down into the formation.

Tofte formation is oil filled. As from figure 1, Gamma ray log values are low that means Tofte fm is sandstone. NPHI (neutron porosity) and RHOB (density log) haven't has larger separation (2670-2705), which is also an indication for oil.

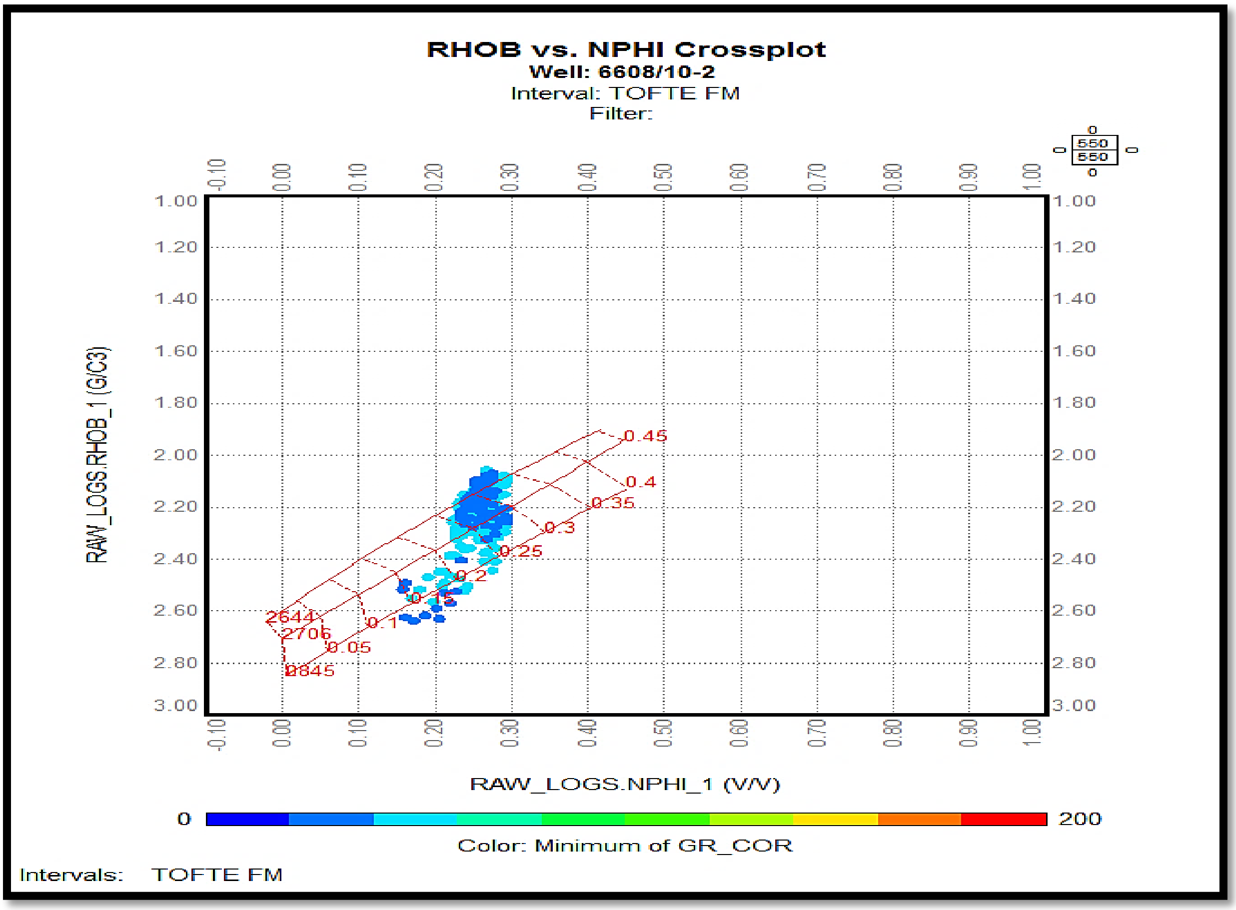


Fig 58: X-plot representing Tofte Formation.

Fig 62 shows cross-plot of Tofte formation between NPHI and RHOB. Three red lines in fig 62 shows lithology (sandstone, limestone, dolomite). Points below first line (sand stone line) shows the presence of oil. Tofte Formstion is very fine to coarse Sand stone.

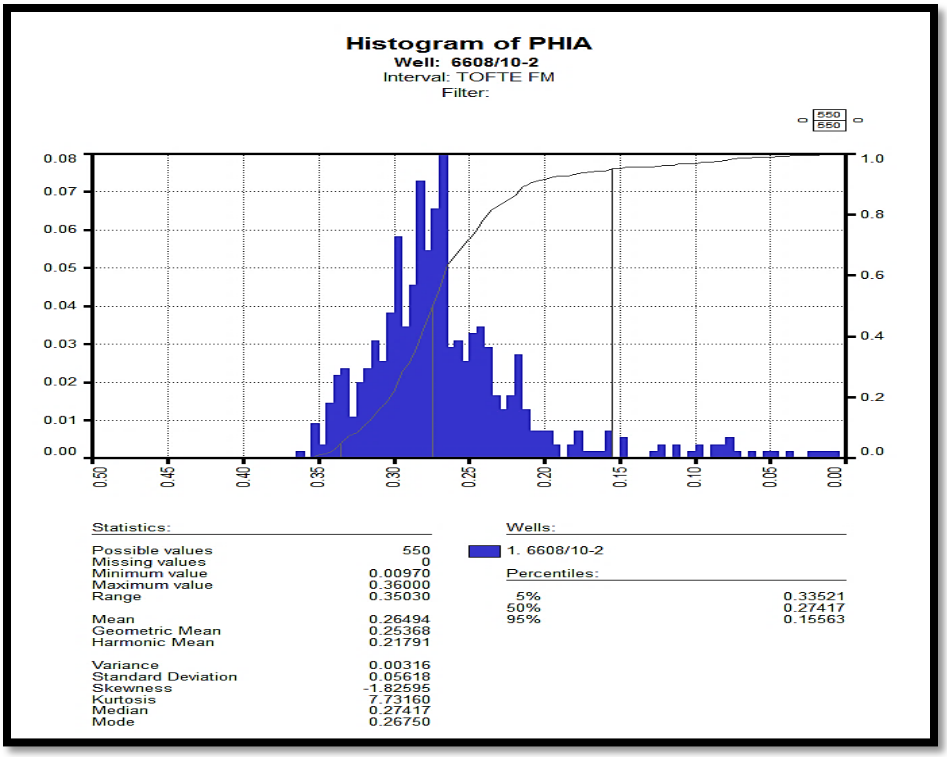


Fig 59: Histogram showing porosity of Tofte formation. Average porsotiy within is 27%.

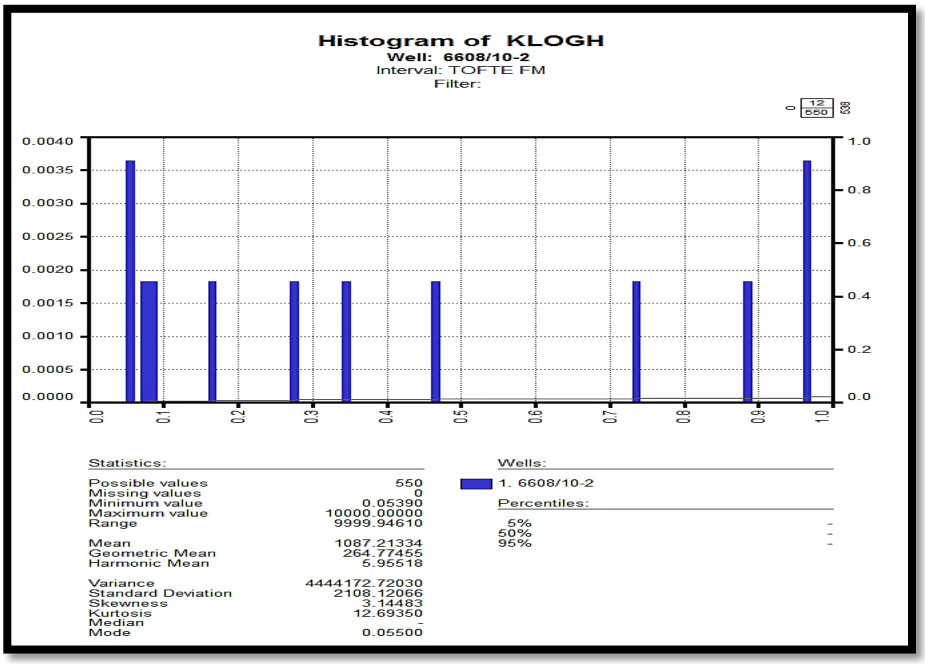


Fig 60: Histogram showing permeability of Tofte formation. Average permeability within is 1087 md.

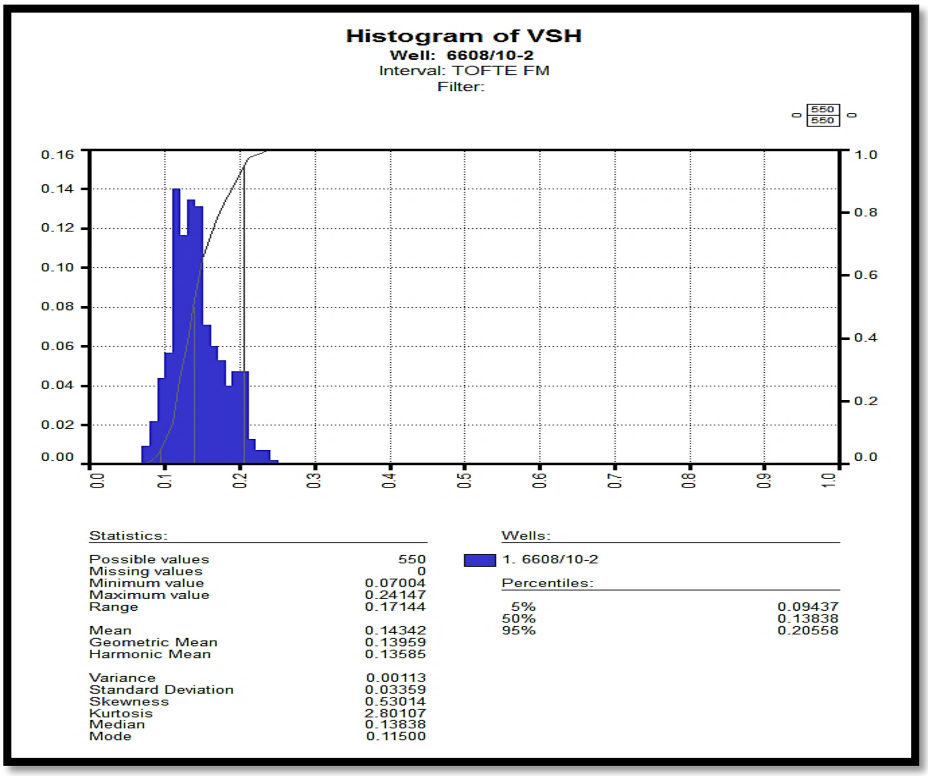


Fig 61: Histogram showing shale voulme of Tofte formation. Average VSH within is 0.14.

Gamma ray in Tofte is quite stable as there isn't any variation in the reading which indicates that the lithology is quite homogenous. The reading depicts that it is clean formation as GR reads on average between (40-82) API, this is further supported by volume of shale (fig 60) , average 14 %.

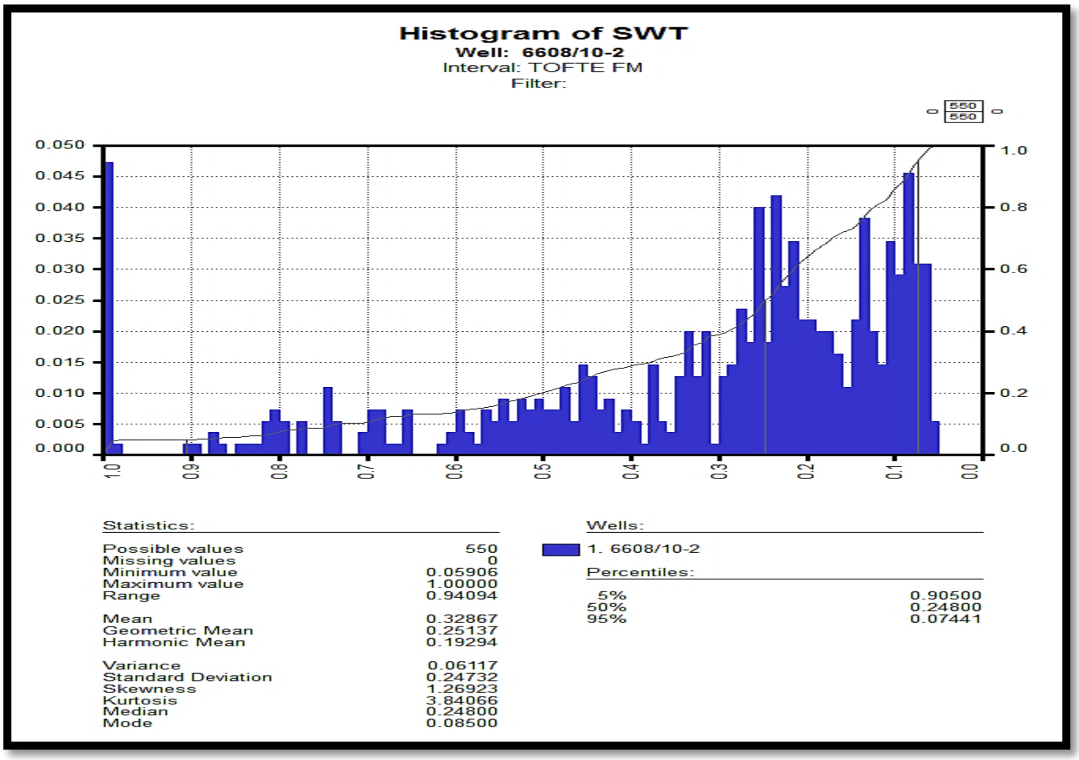


Fig 62: Histogram showing water stauration of Tofte formation. Average SWT within is 0.32.

RT (resistivity log) shows higher resisitivity values. SW (water saturation) shows lower readings while permeability readings are high.Avergae SW (water saturation) is 0.32 in Tofte formation.

Zone	Top Fm.	Bot Fm.	VSH	PHIA	SW	KLOGH
	(m MD RKB)	(m MD RKB)	(frac.)	(frac.)	(frac.)	(frac.)
Tofte	2675	2710	0.14	0.26	0.32	1087

Table 3 : Statistics from Petrophysical Evaluation for well 6608-10/2 Tofte Fm

7.2 Well 6608/10-4.

Drilled at the end of 1993. This well was supdded in the northeast segment, which is located approximately 3 km east of the main structure of Norne. An oil column of 30.5m was discovered in the same structures as the main field. Figure 1 shows the location of the exploration wells.

Table 1: Detail description of well 6609/10-4 (NPD, 2010)

NPDID wellbore:	2256
Well name:	6608/10-4
Drilling operator name:	Den norske stats oljeselskap a.s
Geodetic datum:	ED50
Coordinates:	66° 2` 25.26`` N - 8° 9` 41.74`` E
UTM coordinates:	7324847.23 N - 462006.74 E
UTM zone:	32
Drilled in production licence:	128
Area:	NORWEGIAN SEA
Discovery:	6608/10-4
Field:	NORNE
Drill permit:	776-L
Drilling facility:	ROSS ISLE
Drilling days:	82
Wellbore entry date:	15.12.1993
Wellbore completion date:	06.03.1994
Original wellbore purpose:	WILDCAT
Wellbore purpose:	WILDCAT
Wellbore status:	P&A
Wellbore contents:	OIL/GAS
Discovery wellbore:	YES
Formation/age with hydrocarbons 2:	NOT FM / MIDDLE JURASSIC
Seismic location:	ST 9203-CROSSLINE 2051& INLINE 1230
Kelly bushing elevation (KB) [m]:	23
Water depth [m]:	382
Total Depth (MD) [m]:	2800
Final vertical depth (TVD) [m]:	2800
Max inclination [°]:	3.30
Bottom hole temperature [°C]:	103
Oldest penetrated age:	EARLY JURASSIC
Oldest penetrated formation:	ÅRE FM

7.2.1 Garn formation Well 6608/10-4.

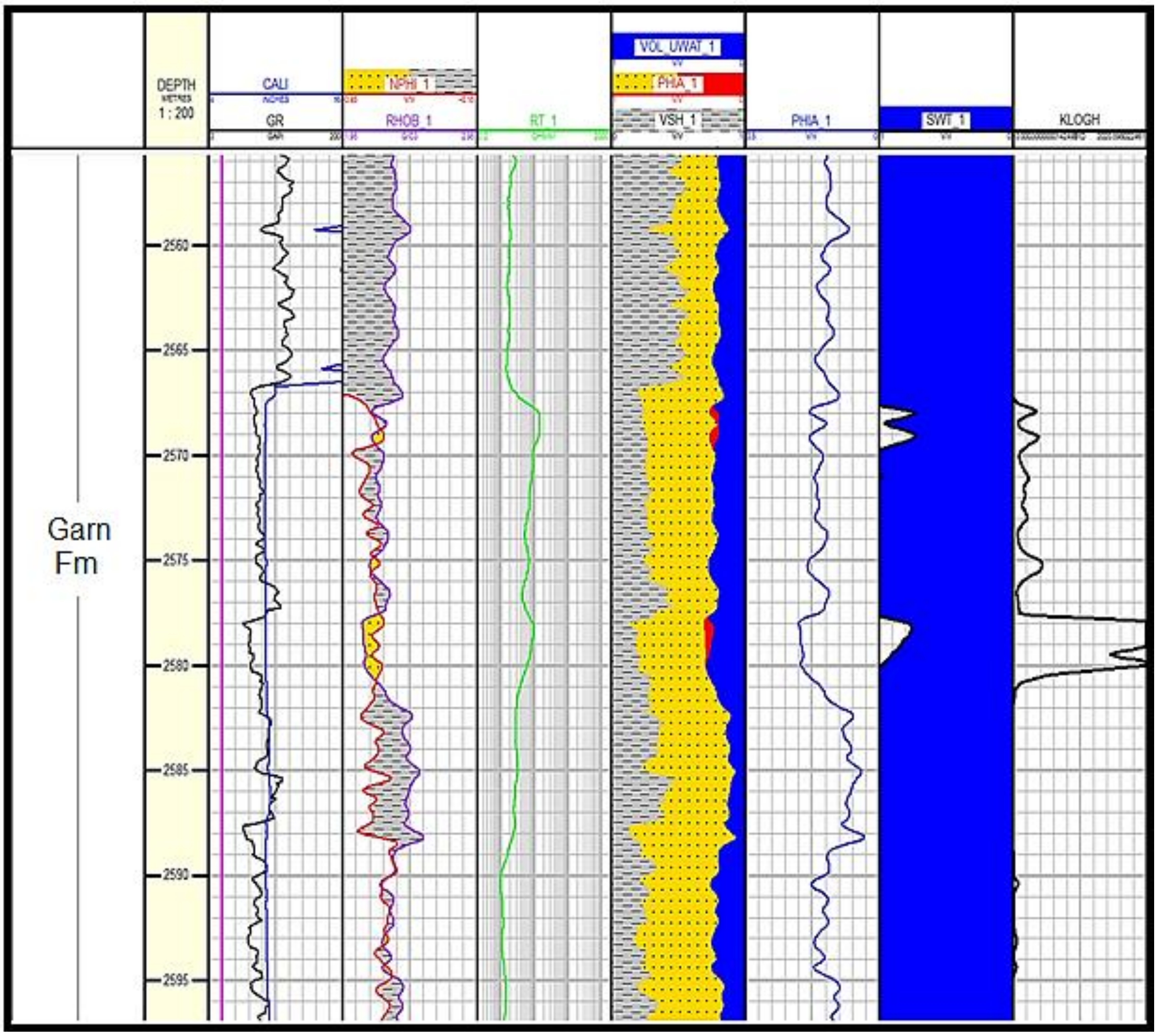


Fig 63: Different logs representing Garn formation

Garn formation is oil filled in well 6608-10/4. As from figure 63, Gamma ray log values are low that means Garn fm is sandstone. NPHI (neutron porosity) and RHOB (density log) have larger separation (2565-2588), which is also an indication for oil. RT (resistivity log) shows higher resisitivity values.

Sand separation (low density and low NPHI) can be observed on RHOB and NPHI log along with high resistivity values on deep resistivity (RT) which further suggests that we have good sands which are oil filled as no gas separation (large separation between RHOB and NPHI) is observed. This interpretation is further supported by density-neutron cross plot figure 64, where most of the data plots between sand and limestone line with good porosity. The data which plots below dolomite line may be associated to sands with high amount of shale.

Garn formation is a fair to good reservoir as log based porosity and permeability varies between (20%,187 md respectively) as figure 69 and 70.

Garn formation is oil filled. As from figure 67, Gamma ray log values are low that means Garn fm is sandstone. NPHI (neutron porosity) and RHOB (density log) haven't has larger separation (2565-2590), which is also an indication for oil.

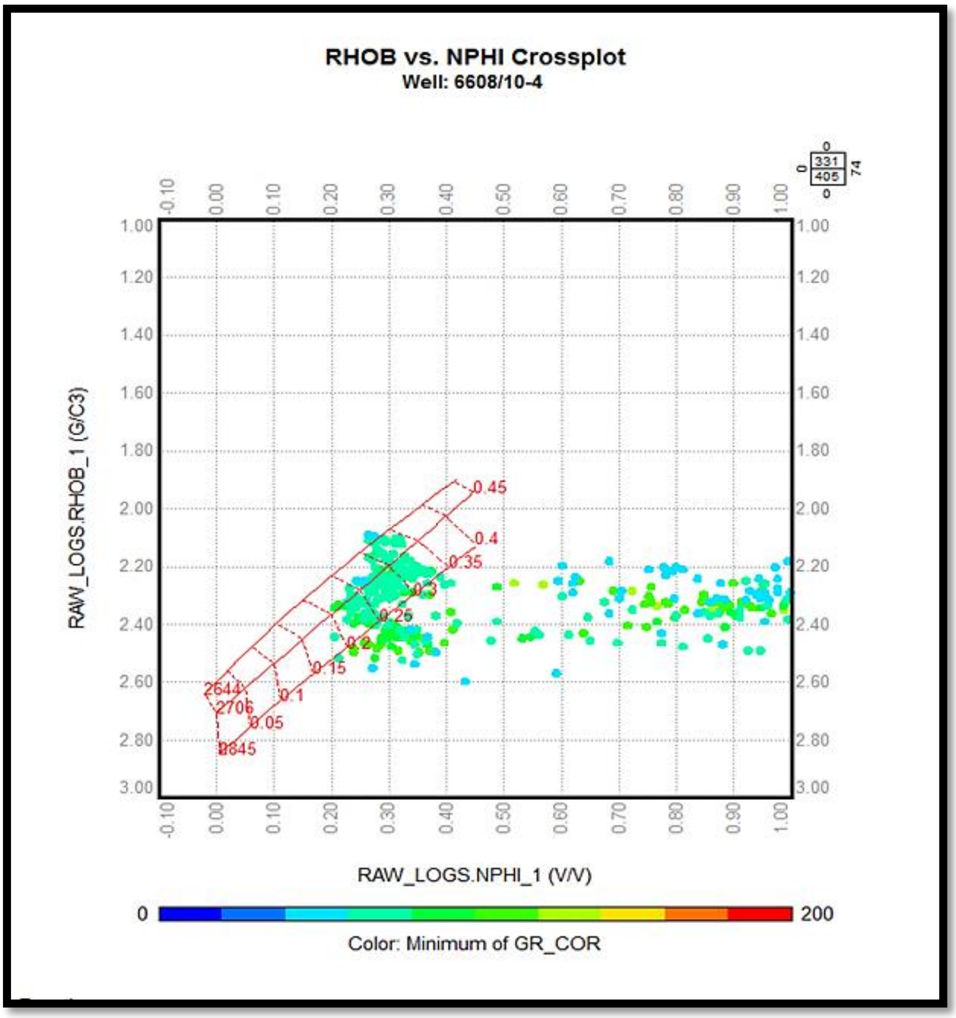


Fig 64: X-plot representing Garn Formation.

Fig 64 shows cross-plot of Garn formation between NPHI and RHOB. Three red lines in fig 64 shows lithology (sandstone, limestone, dolomite). Points between the first and second red line (sand stone and loimestone line) indicates presense of heavier hydrocarbons thenthe one found in well 6608-10/2 as in Garn formation.

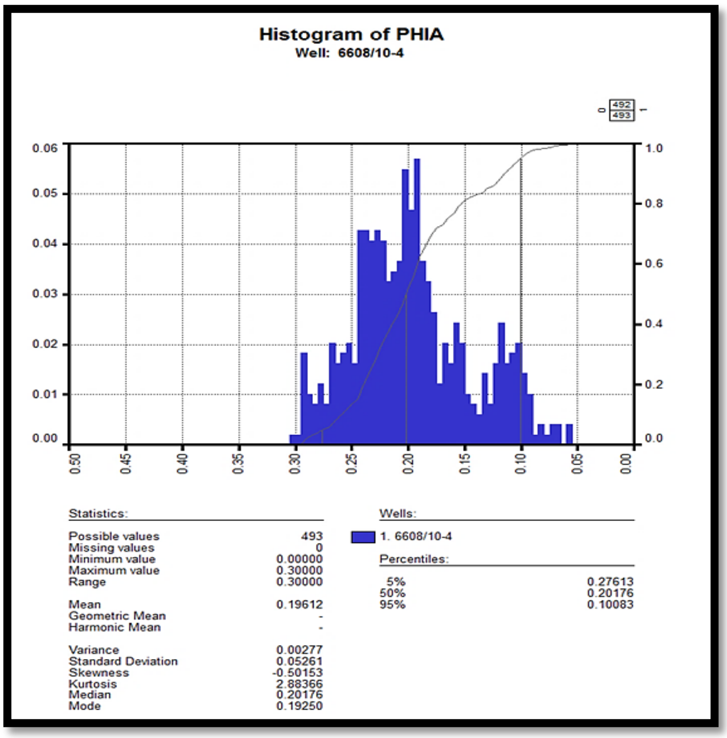


Fig 65: Histogram showing porosity of Garn formation. Average porsotiy within is 20%.

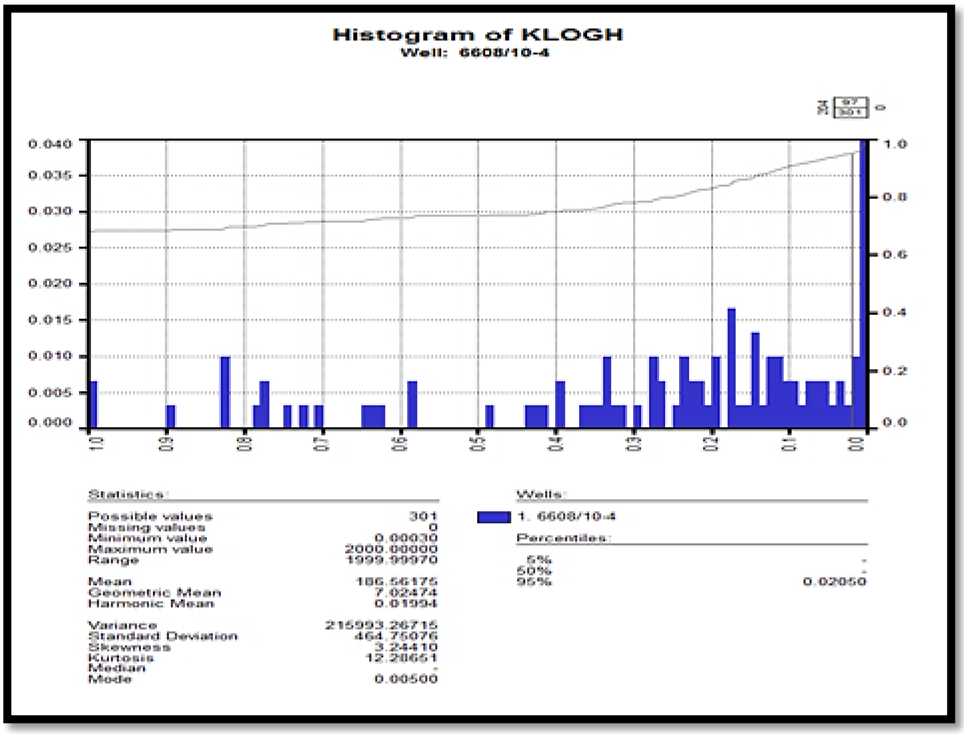


Fig 66: Histogram showing permeability of Garn formation. Average permeability within is 187 md.

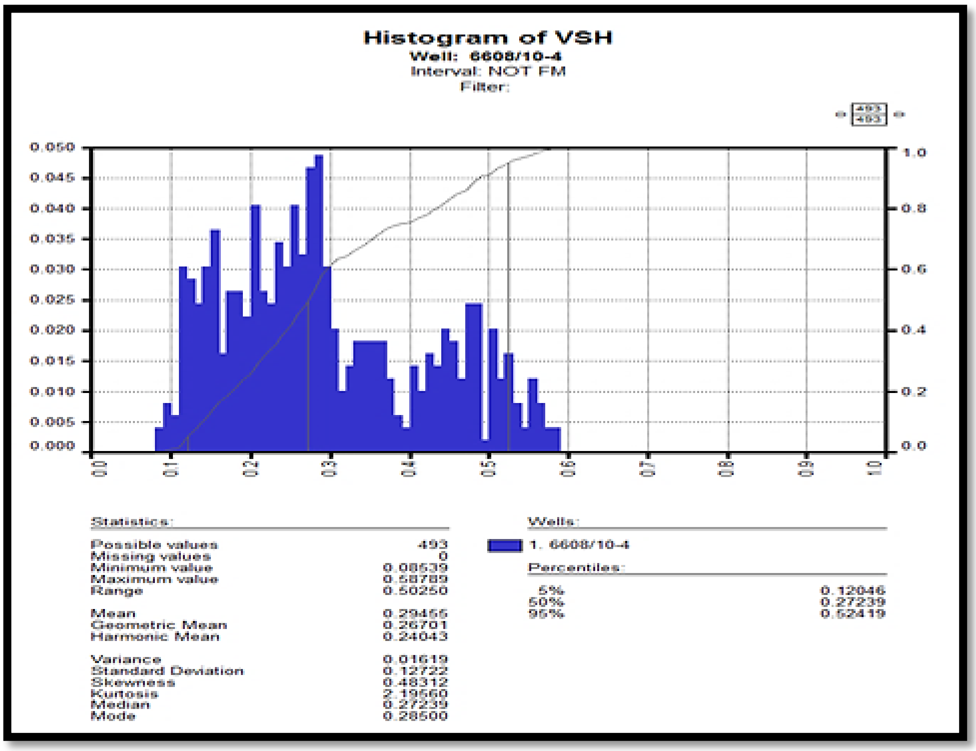


***Fig 67: Histogram showing shale voulme of Garn formation. Average VSH within is 0.29*.**

From the petrophysical analysis and literature (Verlo and Hatland, 2008) it is clear that the reservoir sandstones of Garn formation in the Norne area contains sandstones and shales. The estimated volume of shale may helps to differentiate the sand and shale beds, which helps to evaluate the commercial reservoir intervals (Fig 67). Further, all data points of shale volume from well 6608-10/2 have been plotted in histogram. It is observed that the mean value is approximately 0.29%. This simple but informative histogram shows that the reservoir intervals have clean sandstone of good quality with only minor shale content but unlike well 10/2, 10/4 is filled with oil and water ,not gas.

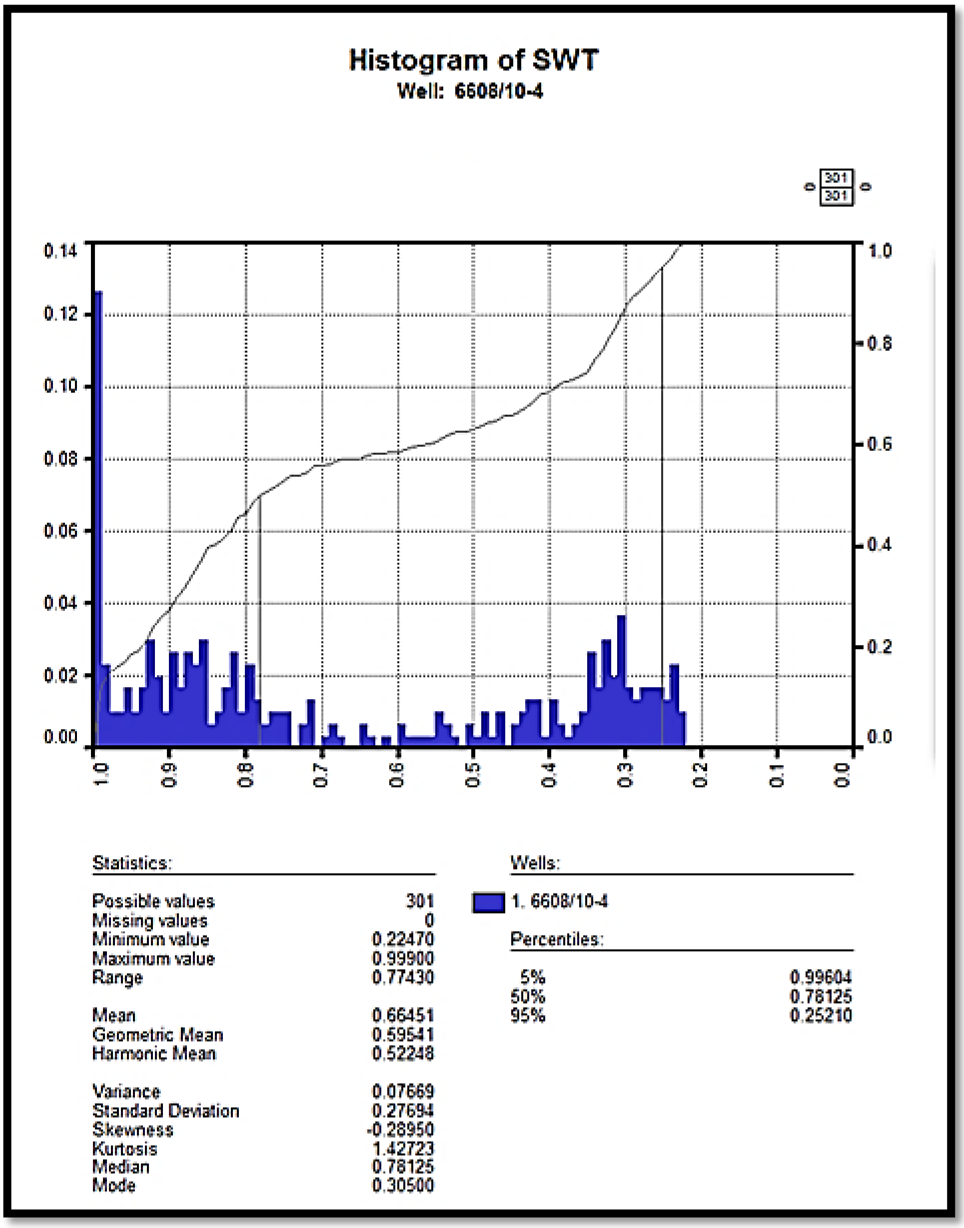


Fig 68: Histogram showing water stauration of Garn formation. Average SWT within is 0.66.

Zone	Top Fm.	Bot Fm.	VSH	PHIA	SW	KLOGH
	(m MD RKB)	(m MD RKB)	(frac.)	(frac.)	(frac.)	(frac.)
Garn	2670	2710	0.29	0.19	0.66	187

Table 1 : Statistics from Petrophysical Evaluation for well 6608-10/4

8 Discussion

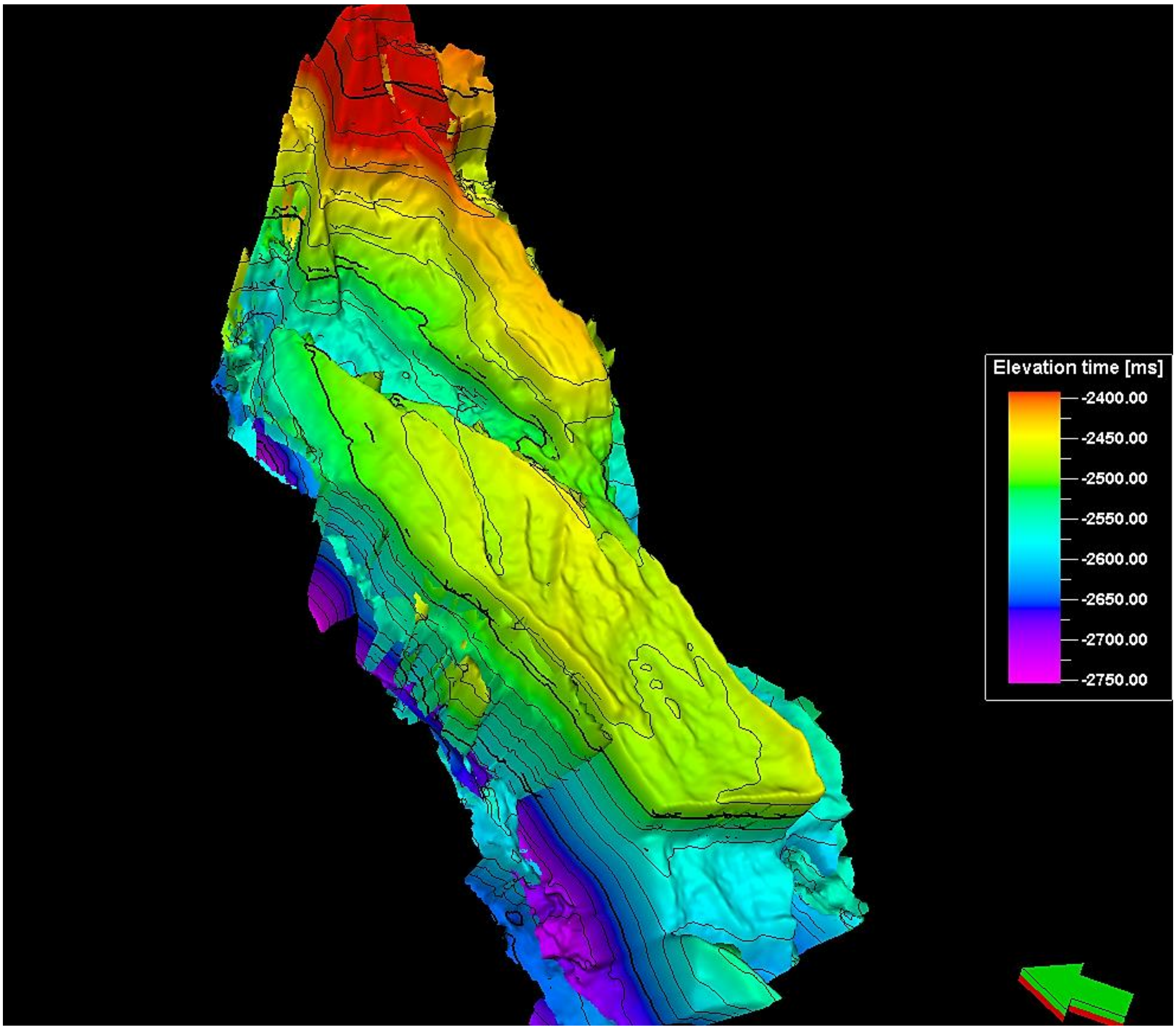


Figure 69: The 4 interpreted 3D surfaces (top-down; Top Garn, Top Ile, Top Tofte,Top Tilje and Top Åre).

All through the interpretation (2D interpretation window) ,geological features have been recognized and interpreted (table 5). Additionally these can be divided into two groups:

- Surfaces
- Structural features
    - Blocks
    - Faults
    - Floors
    - Trench

Following this table, my next steps are to:

- Merge two interpretations
- Systematize structural features
- Observe if some structural features can be interpreted as one
  - Faults
  - Fault blocks
- Inspect reasonable regional faulting to literature

Table : 1

Structural features			
Blocks	Faults	Trenches	Floors
Block C	Fault C-South		C-Floor-South
	Fault C-West		C-Floor-West
	Fault C-East		C-Floor-East
	Fault C-North		
Block G	Fault G-South	DG-Trench	
	Fault G-West		
	Fault G-East		
Block O	Fault O-Internall		
	Fault O-Internal2		
	Fault 0-West		
	Fault 0-East		
Block E	Fault E-West		
	Fault E-East		
Block N	Fault N-West		

Surfaces
Top Spekk
Top Garn
Top lie
Top Tofte
Top Tilje
Top Are

In order to bond the results from to the 2D interpretation to the surfaces created in 3D, I more or less display them all in a full image, optimistically revealing some key outlines (figure 69). The correlation between the 2D and 3D interpretations can more be refined in detail via both coordinates and fault modeling however I will first focus on this more simplistic overview. I want to emphasize the key trends. Alongside organizing and displaying the 2D interpretations this way; we have to keep in mind that particularly the interpreted faults in 2D go all the way down through the 4 surfaces. This may sound palpable, but as an alternative of just investigate the topography of a 3D interpreted surface, maybe erroneously assuming that an eminent area is faulted; from the 2D interpretation we now know that these faults actually cut deep down all the way through the sub surface.

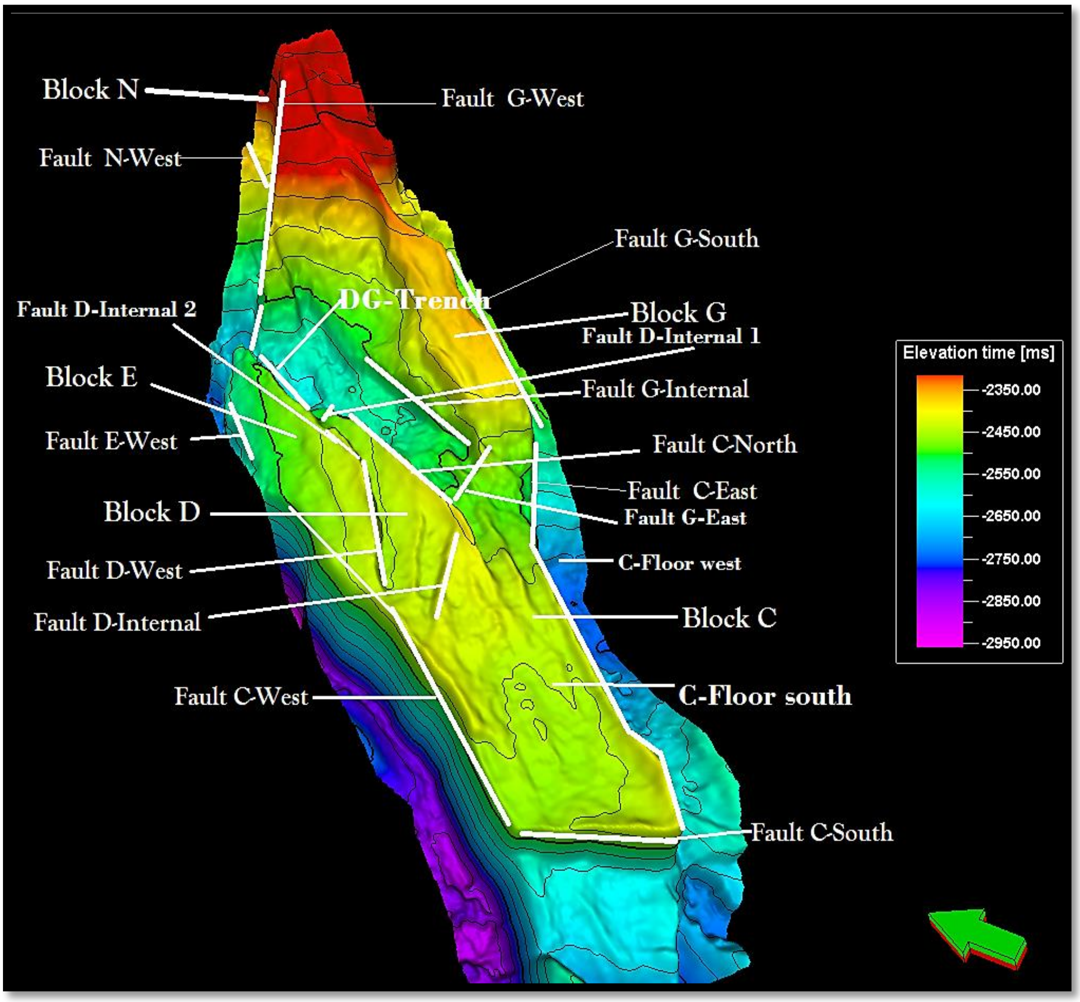


Figure 70: All geological features as interpreted in 2D, ready for 3D studies. At this point I only visualize them as being straight lines. From the 2D interpretation we know that these faults are cutting through the 4 horizons. Furthermore the blocks are being more pronounced as the faults are added. As we see on Top Garn (upper surface), the faults on the eastern side of the field seem to be parts of one single, larger fault.

As mentioned, we can further turn and flip the 3D cube, inspecting these interpreted features in more dtail, but in general structural results are (table 2):

- 5 blocks are evidently outlined and definite by these big faults:
    - Block B
    - Block D
    - Block E
    - Block G
    - Block N

- Faults
  - Faults on the eastern side perhaps belong to one fault; Fault East.
  - Fault D-lnternal 2 appear to be southern part of Fault E-East
    - This could mean that Fault D-East persist northward, somewhat parallel to and east of Fault E-East
  - Fault C-North and Fault G-North may small parts of a more intricate NS going fault system; Faults CG
  - Fault C-East and Fault G-East may be the same north going fault; Fault West
- Trenches
  - Probably being a graben in between the D and G blocks, I still call It the DG-Trench for now
- Floors
  - Being the same surfaces defining the blocks, for now we leave them out

Table 2

Structural features		
Blocks	Faults	Trenches
Block C	Fault C-South	
	Fault West	
	Fault East	
	Faults CG	
BlockG	Fault G-West	DG-
	Fault G-East	
Block D	Fault D-West	
	Fault D-Internal	
	Fault D-East	
Block E	Fault E-East	
Block N	Fault N-West	

Surfaces
Top Spekk
Top Garn
Top lie
Top Tofte
Top Tilje
Top Are

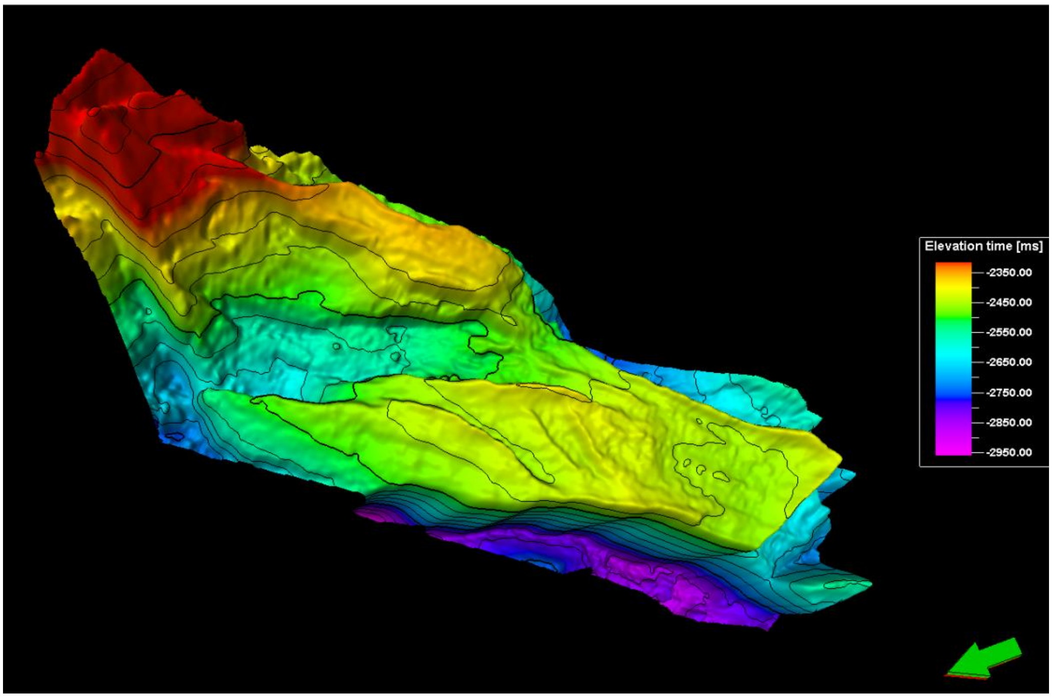


Figure 71: The familiar Top Garn surface as interpreted in 3D.

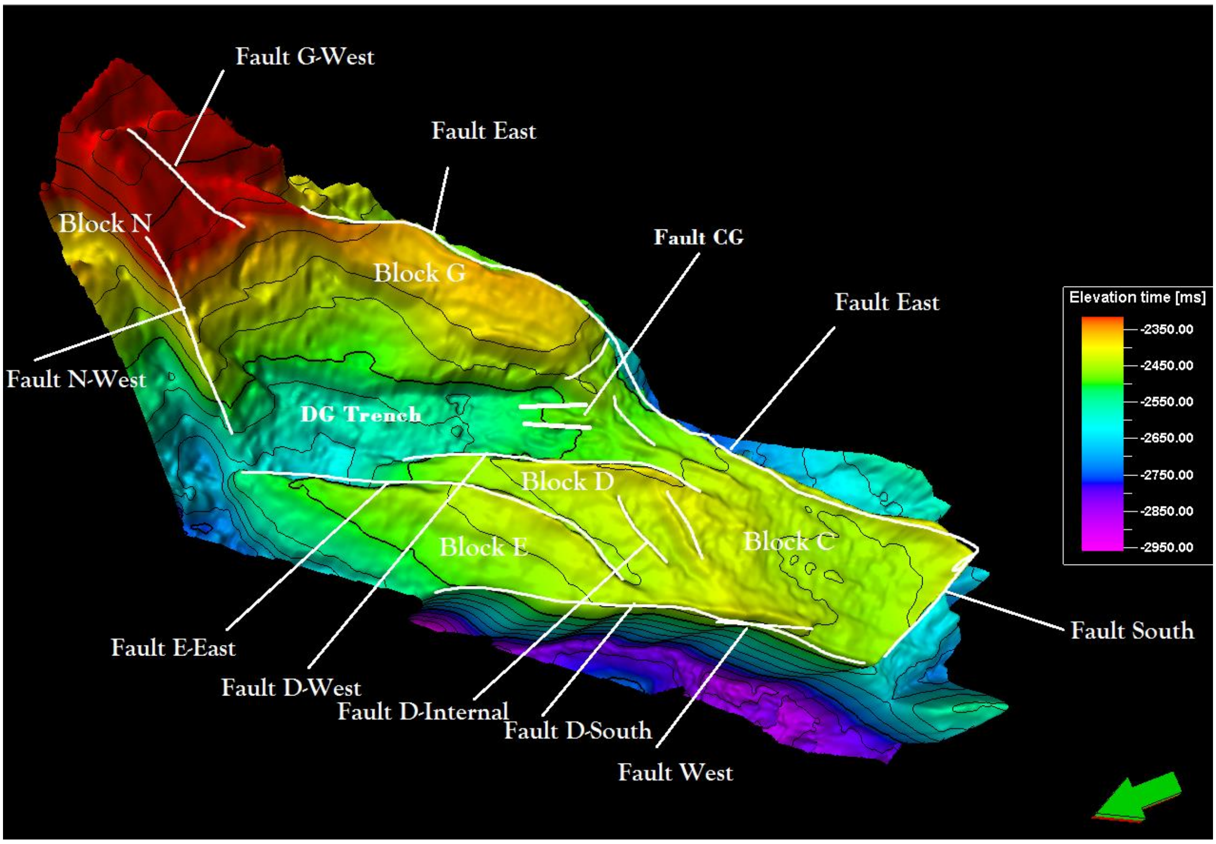


Figure 72: Adding some more complexity to the updated faults and we see how It follows the natural topography.

8.1 Comparing Results

One of the purposes in this thesis was to compare the final Top Garn surface to one specified, top reservoir surface from literature. As the layers deep beneath the seafloor are hard to envisage by nature, having such an orientation can help me with:

- The interpretation itself (from a practical point of view)
- Geological features
  - Some features have already been acknowledged and given names
- Final comparison
  - Did I successfully interpret parts of the Norne field?
    - What went well?
    - What could be better?
  - In general, did my approach work?
    - If so, would I be able to do interpret parts of an unknown reservoir?

By evaluating results to work in the past done by professionals may answer some of these questions (figure 73). Even though, we keep in mind that this appraisal is relative to the already produced results. However, as the first point; it is hard to weigh up my results any other way as I write this thesis.

Monitoring the Top Garn surface from the same point of view as the given surface, I can clearly see if I have interpreted some of the main geological features correctly (figure 74).Just as I made some simplification s and re-interpretations in the earlier sub-chapter, I now only focus on Block C, D, E and G. The simple reason for doing so is that these blocks have already been recognized on the given surface (figure 74); I here present a quick summary of what I see.

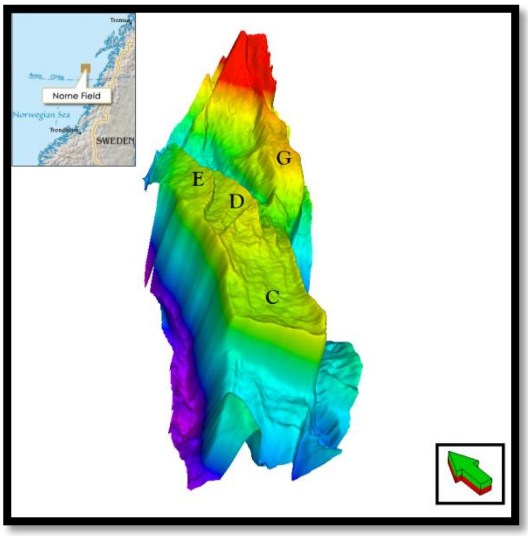


Fig 73: Top Garn with 4 blocks

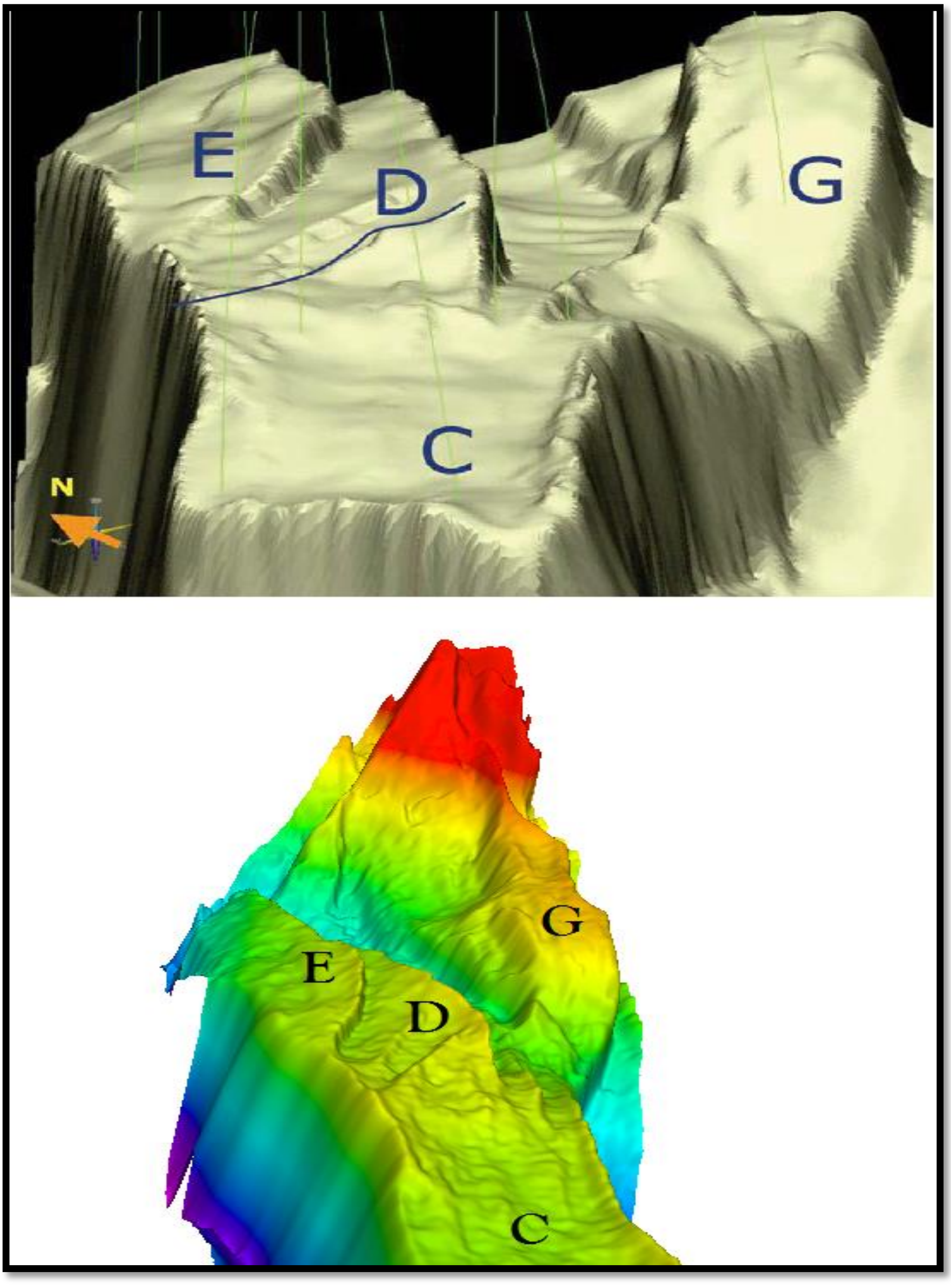


Fig 74: Top reservoir (top) map showing Norne horst block with four segments. (Osdal et al., 2006) My interpretation of Top reservoir (bottom).

8.1.1 Block C

This most likely is the correctly interpreted block. Fault South, Fault West and Fault East visibly outline the block in both images, even though we see how the related layer on the eastern side of the block (C-Floor-East), may be located fairly lower down. Some of the elevated part in the N-central section of the block also can be seen in both images. Most likely the significant feature is the elevated border around the block; the overall interpretation of Block C seems to be good enough and could be subject to further detailed studies such as internal faults and reservoir compartments.

8.1.2 Block D

In a like way as for Block C, the eastern side of block D (Trench DG) seem to be interpreted fairly to high to me. Typically if I could ways in more surfaces like these and my goal was to further process my interpretation, this area could be subject to further studies in terms of extra interpreted seismic 2D lines, lithology data from close wells etc. Still, the specified surface may also be idealized outside the block itself so my interpretation of Trench DG still could be fairly correctly interpreted. When comparing the two images, I think that Fault D-lnternal and Fault D-South are well interpreted (see figure 72 for nomenclature and how well these faults match in figure 74). When correlating features like these falls in place, the interpretation really is pressed forward (hopefully in the right direction). Block D also borders Block E in a similar way in both images. Block D looks acceptable.

8.1.3 Block E

As the given surface only can be seen from this viewpoint, block E is not easily seen. Still, Fault E-East already is described as solid fault interpretation and Fault West has also been well recognized as the principal SW-NE trend. Still Block E looks satisfactory and we keep in mind that the real perspective is not identical (the given surface seem to be somewhat warped).

8.1.4 Block G

Relative to the given surface, Fault G West and the northern part of Fault East (along block G) is not healthy interpreted. Some of the slight southern faults and the central parts of the block itself seem to be satisfactory. Still, the assessment suggests that Block G most likely should be subject for further studies or even a full re-interpretation.

8.2 Regional Geology and Large Scale Fault Complexes

As final statement on the major faults discussed here, it could be interesting to see how Fault East and Fault West behave the whole time a larger regional seismic volume. From literature figure 4 and figure 6,we know that the key fault trend outlining the Nordland ridge primarily is going in the SW-NE direction. When we compare these images from literature to the interpreted Fault East and Fault West, we evidently see the SW-NE trend (figure 75). Such larger view of the prime faults can reveal further geological evolution and present day data about the faulted reservoir.

Also, a quick look at the given surface in figure 74 propose that Block D and Block G once was one vast block, rifted apart by extensional forces going in the NW-SE direction; they appear to fit like two pieces of puzzles (in a comparable way that the west coast of Africa fits into the east coast of South America). This just is an easy scrutiny; further studies of reasonable fault patterns may improve this theory.

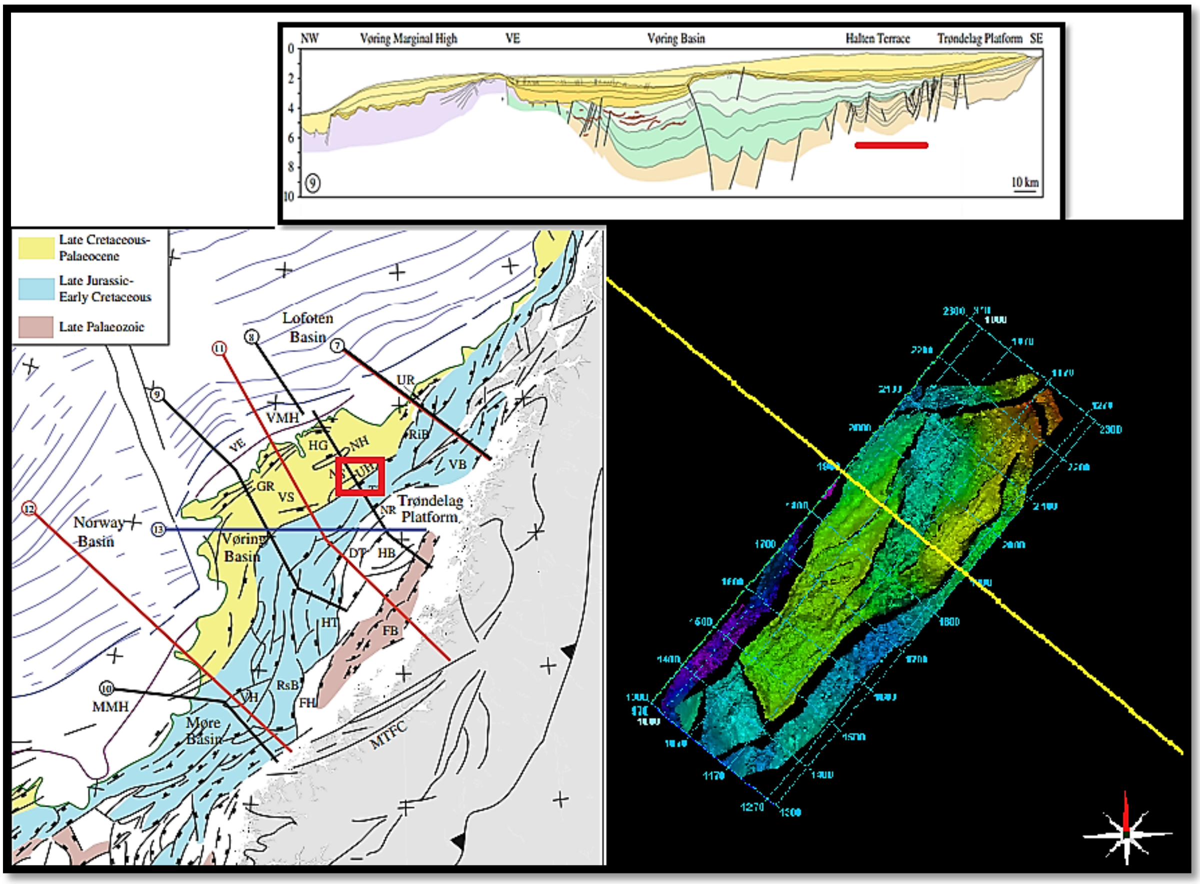


Figure 75: A regional profile (left image, red box) with Crossline 1900 at the surface map right Image, yellow line). As we see, the Norne field (black background) is located NE of the regional profile. However Fault West and Fault East outlining the entire reservoir seem to follow the same SW·NE trend as the principal faulting along the Nordland ridge. Although outside the scope of this thesis, a more detailed study of these large fault patterns could possible help the interpretation and the overall understanding of the reservoir. In the regional profile I also have marked what appears to be the continuation of these large faults (red line top figure).

8.3 Petrophyscis

Now I'll compare petrophysical evaluation of different reservoirs.

Zone	Top Fm.	Bot Fm.	VSH	PHIA	SW	KLOGH
	(m MD RKB)	(m MD RKB)	(frac.)	(frac.)	(frac.)	(frac.)
NOT	2565	2615	0.31	0.19	0.36	278
ILE	2615	2660	0.15	0.24	0.20	494
Tofte	2675	2710	0.14	0.26	0.32	1087

Table 5 : Statistics from Petrophysical Evaluation for well 6608-10/2

This table shows difference in Volume of shale, porosity, water saturation and permeability of three different reservoirs in well 6608-10/2.

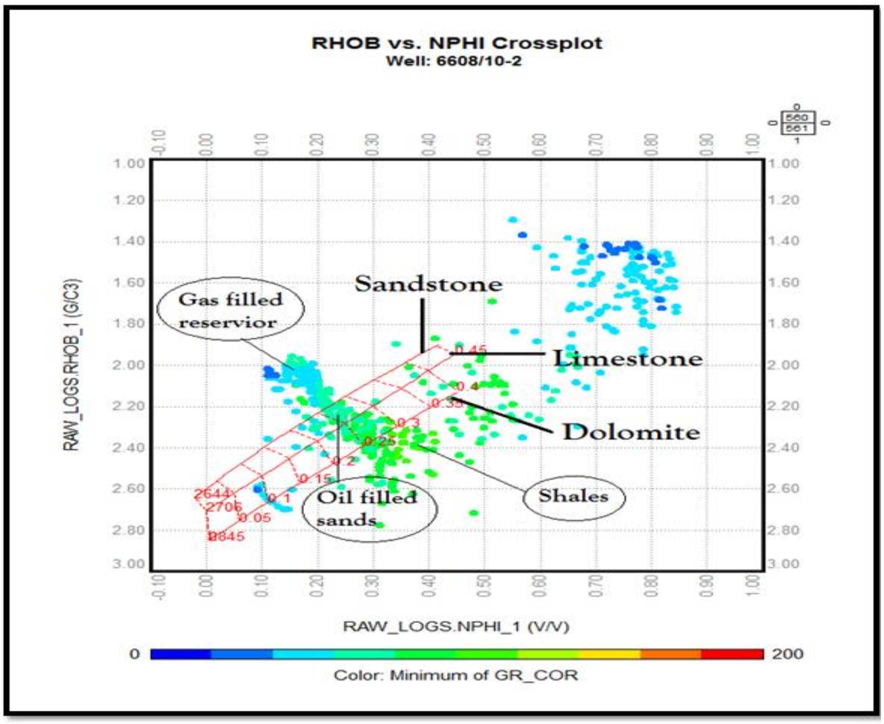


Fig 76: X-plot representing Garn Formation.

In Fig 76 three red lines shows lithology (sandstone, limestone, dolomite). Points above sandstone line represents the presence of gas. Garn Formstion is a Sand stone.Point below dolomite line represents shales. As Garn formation is sandstone in the middle and shale on upper and lower parts. Cluster of points above sandstone line suggests that this reservoir is a gas filled.

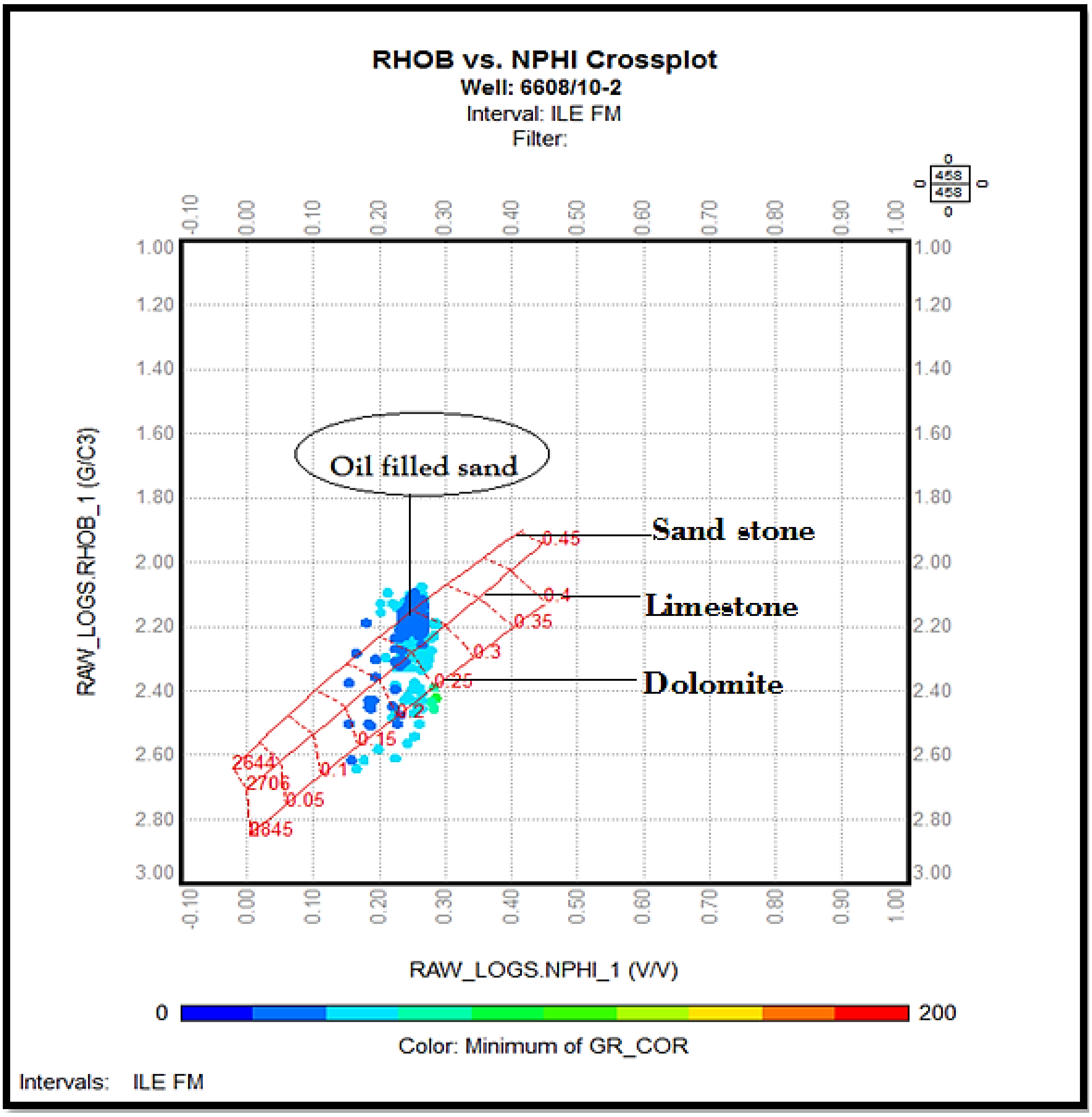


Fig 77: X-plot representing Ile Formation.

Fig 77 shows cross-plot of Ile formation between NPHI and RHOB. Three red lines in fig 77 shows lithology (sandstone, limestone, dolomite). Ile Formstion is a Sand stone. Cluster of points below sand line indicates presense of oil in this formation.

The Ile Formation was deposited during the Aalenian, and is about 32-40 m thick sandstone. The depositional environment of Ile formation was in the shoreface. The reservoir quality of the Ile Formation is generally fair to good, especially in the regressive depositions, whereas the reservoir properties are decreasing towards the top of the formation.

Tofte formation is oil filled. As from figure 57, Gamma ray log values are low that means Tofte fm is sandstone. NPHI (neutron porosity) and RHOB (density log) haven't has larger separation (2670-2705), which is also an indication for oil. RT (resistivity log) shows higher resisitivity values. SW (water saturation) shows lower readings while permeability readings are high.

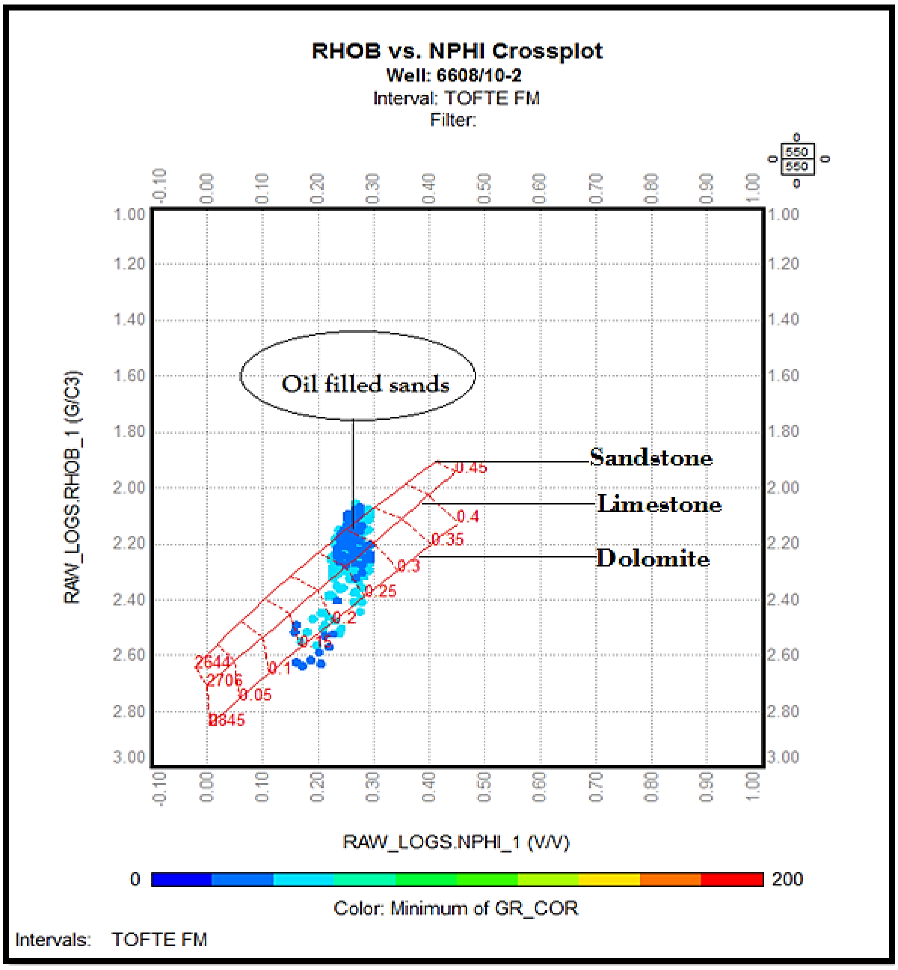


Fig 78: X-plot representing Tofte Formation.

Fig 78 shows cross-plot of Tofte formation between NPHI and RHOB. Three red lines in fig 78 shows lithology (sandstone, limestone, dolomite). Points below first line (sandsyone line) shows the presence of oil. Tofte Formstion is very fine to coarse Sand stone.

the Tofte Formation is anticipated to be about 50 meters thick in average through out the field. Marine from foreshore to offshore environments seem to portray the formation. Sands were deposited in to the west of the Nordland ridge, while finer shales can experimental to the east. At the top of the ridge marks of erosion also have been found. The subdivisions of the Tofte Formation are the Tofte 1, 2 and 3 reservoir zones.

8.3.1 Garn formation Well 6608/10-4.

Oil was found in Garn formation in well 6608/10-4. As from figure 62, Gamma ray log values are low that means Garn fm is sandstone. NPHI (neutron porosity) and RHOB (density log) have larger separation (2568-2588), which is also an indication for oil. RT (resistivity log) shows higher resisitivity values.

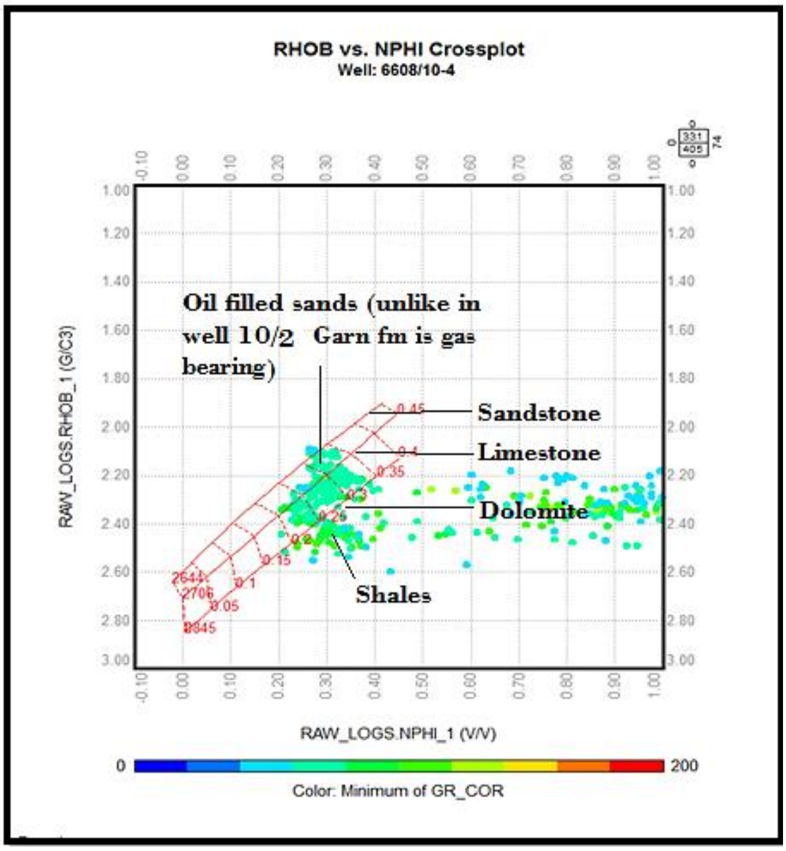


Fig 79: X-plot representing Garn Formation.

Fig 79 shows cross-plot of Garn formation between NPHI and RHOB. Three red lines in fig 79 shows lithology (sandstone, limestone, dolomite).Garn formation is an oil filled reservoir here unlike in well 6608-10/2, where Garn fm is gas bearing reservoir.

8.4 Relationship between Petrophysical evaluation and Seismic

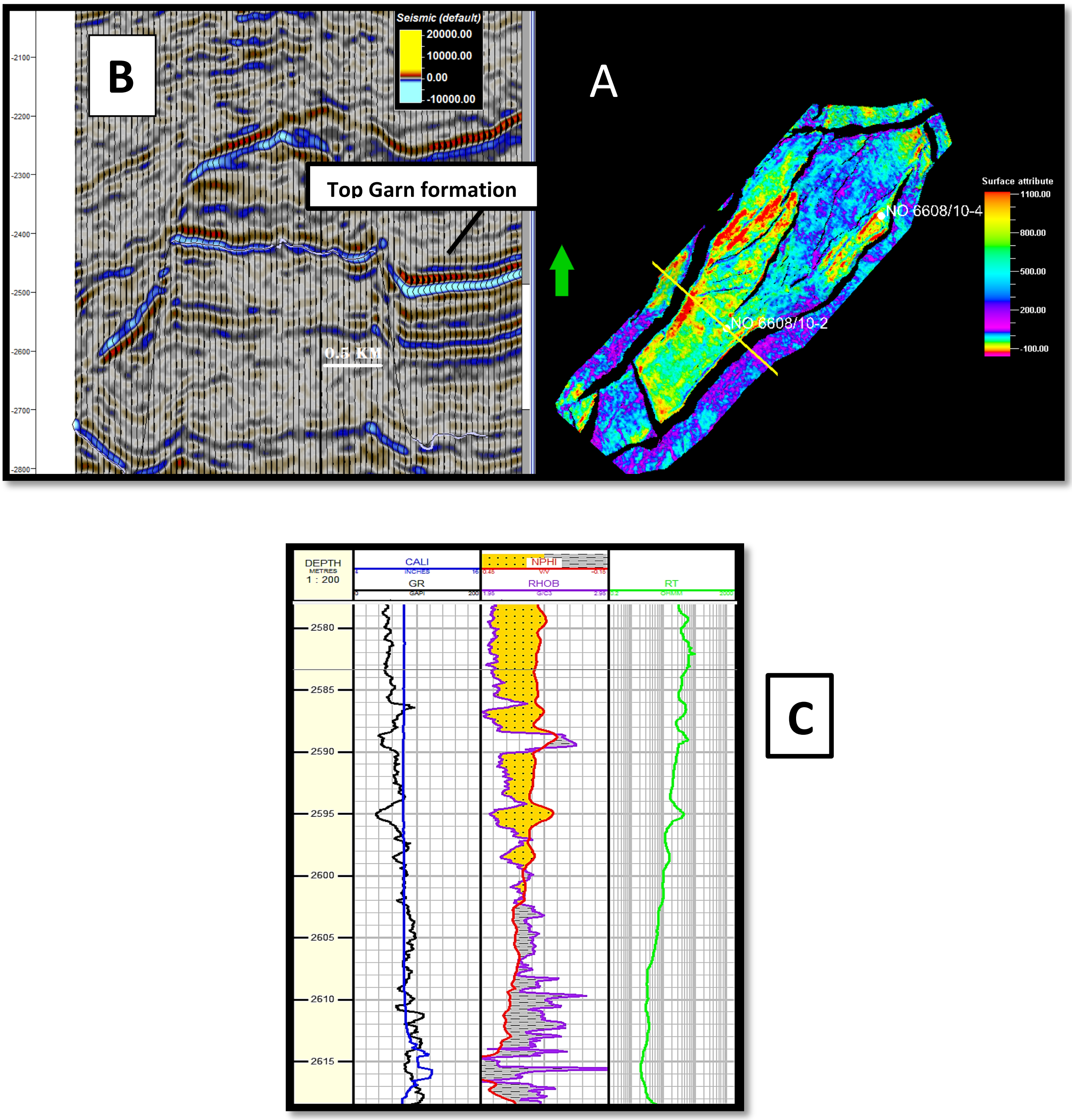


Figure 80: A) Representation of RMS map of Top reservoir (garn formation) with wells location and Seismic line B. B) Indicates the high amplitude anomaly on cross line 1663. C) CPI (computer processed interpretation) of Top reservoir(Garn formation), showing logs Gamma ray, Caliper, Neutron porosity, Density and resistivity.

As we can observe high amplitude anomaly in seismic section in Top Garn formation in figure 80 due to high acoustic impedance contrast. This acoustic impedance contrast resulted by decrease in density. This high amplitude could be the indication of hydrocarbon presence in formation. This high amplitude anomaly can be observed on the RMS amplitude map. As we can observe from the logs in figure 80 that gamma ray values are low and there is cross over between Neutron porosity and Density log, which indicates the possible hydrocarbon contents in Sandstone reservoir (Garn formation). These hydrocarbon contents show high resistivity values on resistivity log in figure..

Garn formation in well 6608-10/2 is gas bearing reservoir (from petrophysical evaluation in this thesis) which means that its quite safe to say that amplitude anomalies are indication of hydrocarbons.

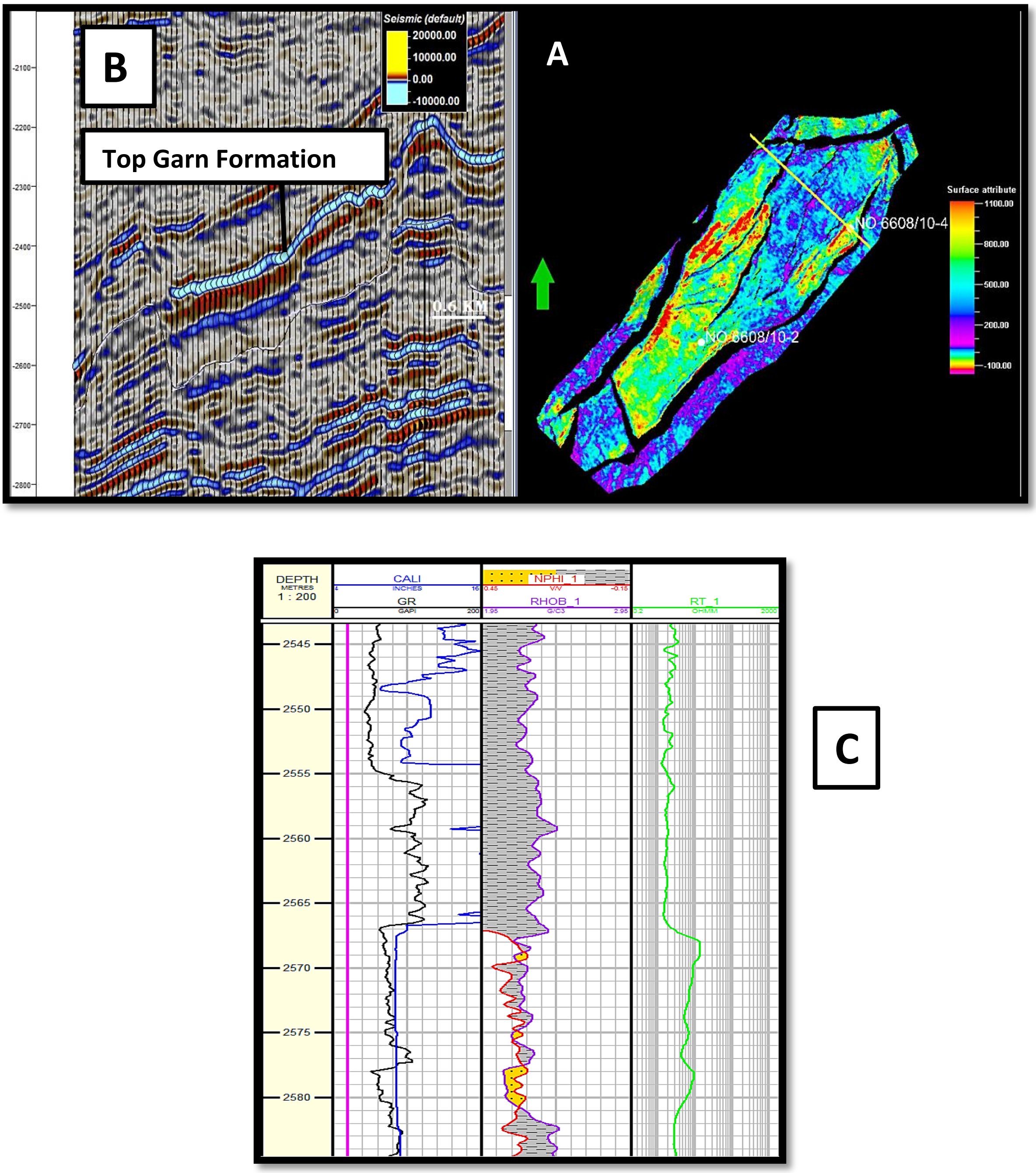


Figure 81: A) Representation of RMS map of Top reservoir (garn formation) with wells location and Seismic line B. B) Indicates the high amplitude anomaly on cross line 2050. C) CPI (computer processed interpretation) of Top reservoir(Garn formation), showing logs Gamma ray, Caliper, Neutron porosity, Density and resistivity.

In figure 81 we can see high amplitude anomaly in seismic section in Top Garn formation due to high acoustic impedance contrast. This acoustic impedance contrast resulted by decrease in density. This high amplitude could be the indication of hyrocarbon presence in formation. This high amplitude anomaly can be observed on the RMS amplitude map. As we can oberve from the logs in figure 81 that gamma ray values are not same throughout and there is cross over between Neutron porosity and Density log, but cross over is not wide like the one we observed in figure 80 , Cross-over indicates possible hydrocarbon contents in Sandstone reservoir (Garn formation). These hydrocarbon contents show high resistivity values on resistivity log in figure 81 but lower than the restivity values we observed in figure 80, we have hydrocarbon indication in this reservoir.

Garn formation in well 6608-10/4 is oil bearing reservoir (from petrophysical evaluation in this thesis) because cross over between neutron porosity and density is not big and RT values are low as compared to RT values of Garn formation in well 6608-10/2 which means that its quite safe to say that amplitude anomalies are indication of hydrocarbons here as well.

9 Conclusions

Primary Focus of this thesis were to evaluate Petrophysical properties of Norne Top reservoir (Garn formation).Which includes understanding of different logs and then evaluating different petrophysical properties like porosity, shale volume , water saturation, hydrocarbon saturation, permeability and etc.Petrophysical evaluation took place using two wells, 6608/10-2 and 6608/10-4.

Second objective was to interpret the top reservoir surface (Top Garn surface), the cap rock (Top Spekk surface), lIe, Tofte, Tilje and Åre top with major faults, to get an overview of Norne field's different structural elements and stratigraphy. I decided to interpret 14 lines (Seismic lines).

As the understanding of the primary objective gives me knowledge about reservoir quality and properties, the secondary objective helped me building an overall seismic understanding of the reservoir.

Garn formation (top reservoir), is a good reservoir in both wells with average porosity of 20 % and 19% in wells 10/2 and 10/4 respectively. In well 10/2 , Garn formation is a gas bearing reservoir while in 10/4, it is an oil bearing reservoir. Ile and Toft, both reservoirs are fine to good qaulity. With porosity of 23 % and 25% respectively in well 10/2 and both are oil bearing reservoirs. In well 10/4, Ile and Tofte, both are water filled reservoirs.

In seismic interpretation, I've interpreted the top reservoir (Top Garn) with the cap rock (Top spekk), Ile, Tofte and Åre formation with major faults (FC-South, West, East, CG, G-West, G-East, D-West, D Internal, D-East, E-East and N-West) and the relative fault blocks (Block C, D, E and G).

As a background story, in geological terms I presented the evolution and present day situation in both regional (Mid-Norwegian Continental Shelf) and local (reservoir) scales. Just by drawing a simple line through space and time like this, I felt how these theories and observations indeed made sense and fell in place, i.e. the return back from reservoir to regional scale in the discussion. Furthermore, I added as much needed information about the reservoir as possible to the mix; lithology data from logs, correlated well top names from appropriated check shots, how to imagine the sub surface geology by drawing a simple sketch and an improvised well trajectory; with known lithology columns and well coordinates from the NPD pages.

As technology advances, both in terms of software capacity and knowledge from the field, the amount of information increases. Expanding the life time of a field is not a simple task. However, we keep on building on whatever we already know.

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